Kemper County Storage Complex

Proposed Injection Well 19-2

Mississippi Power Company

Area of Review and Corrective Action Plan

40 CFR 146.84(b)

Facility Information

Facility Name:	Kemper County Storage Complex Well Name: MPC 19-2
Facility Contact:	Mississippi Power Company Environmental Affairs P.O. Box 4079 Gulfport, MS 39502-4079
Well Location:	Kemper County, Mississippi Latitude: 32.6130560 Longitude: -88.8061110

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List of Acronyms/Abbreviations

AoR	Area of Review
CCUS	Carbon capture, utilization, and storage
CO_2	Carbon dioxide
CMG	Computer Modelling Group
DOE	Department of Energy
ECO_2S	Establishing An Early Carbon Dioxide Storage
EPA	Environmental Protection Agency
ERRP	Emergency and Remedial Response
ft	feet
mg/L	milligrams per liter
MMt	Millions of Metric tons
MPC	Mississippi Power Company
PCC	Porters Creek Clay
PISC	Post-Injection Site Care
psi	Pounds per square inch
RCA	Routine Core Analysis
SS	Sub-Sea
TMS	Tuscaloosa Marine Shale
TVD	True Vertical Depth
UIC	Underground Injection Control
USDW	Underground Source of Drinking Water

A.0 AoR Delineation Using Computational Models

The Area of Review (AoR) describes the region within the Kemper County Storage Complex where USDWs may be endangered by injection activity. The AoR is delineated by the lateral and vertical migration extent of the CO_2 plume and pressure front in the subsurface. The threshold of the pressure front is determined by the minimum pressure sufficient to cause movement of injected fluids or formation fluids into a USDW. The lateral and vertical migration extent of the CO_2 plume, formation fluids, and the pressure front was determined by geologic site characterization and computational modeling. After injection commences, monitoring and operational data will be added to ongoing modeling efforts to continue reevaluating and validating the AoR.

A.1 AoR Delineation Class VI Rule Requirements

According to the EPA UIC Class VI Well Area of Review Evaluation and Correction Action Guidance, the following Class VI Rule requirements apply to AoR delineation:

• 40 CFR 146.84(a): The AoR is the region surrounding the Geologic Sequestration (GS) project where USDWs may be endangered by the injection activity. The AoR is delineated using computational modeling that accounts for the physical and chemical properties of all phases of the injected carbon dioxide stream and is based on available site characterization, monitoring, and operational data.

• 40 CFR 146.84(c)(1): Owners or operators of Class VI wells must predict, using existing site characterization, monitoring and operational data, and computational modeling, the projected lateral and vertical migration of the carbon dioxide plume and formation fluids in the subsurface from the commencement of injection activities until the plume movement ceases, until pressure differentials sufficient to cause the movement of injected fluids or formation fluids into a USDW are no longer present, or until the end of a fixed time period as determined by the UIC Program Director. The model must:

> (i) Be based on detailed geologic data collected to characterize the injection zone(s), confining zone(s), and any additional zones; and anticipated operating data, including injection pressures, rates, and total volumes over the proposed life of the GS project;
>
> (ii) Take into account any geologic heterogeneities, other discontinuities, data quality, and their possible impact on model predictions; and
>
> (iii) Consider potential migration through faults, fractures, and artificial penetrations.

A.2 Data Collection and Compilation

A.2.a Site Hydrogeology

Proposed injection well MPC 19-2 (**Figure 1**) at the Kemper County Storage Complex will inject CO_2 into the sandstones of the Lower Cretaceous-age Paluxy Formation. Information on the injection, confining and overlying formations was collected during the drilling of six characterization wells by MPC. Wireline logs and core analysis were performed at each well. In addition, preexisting 2D seismic lines were acquired within Kemper County to further define the occurrence, extent and thickness of the storage zones and their sealing units.

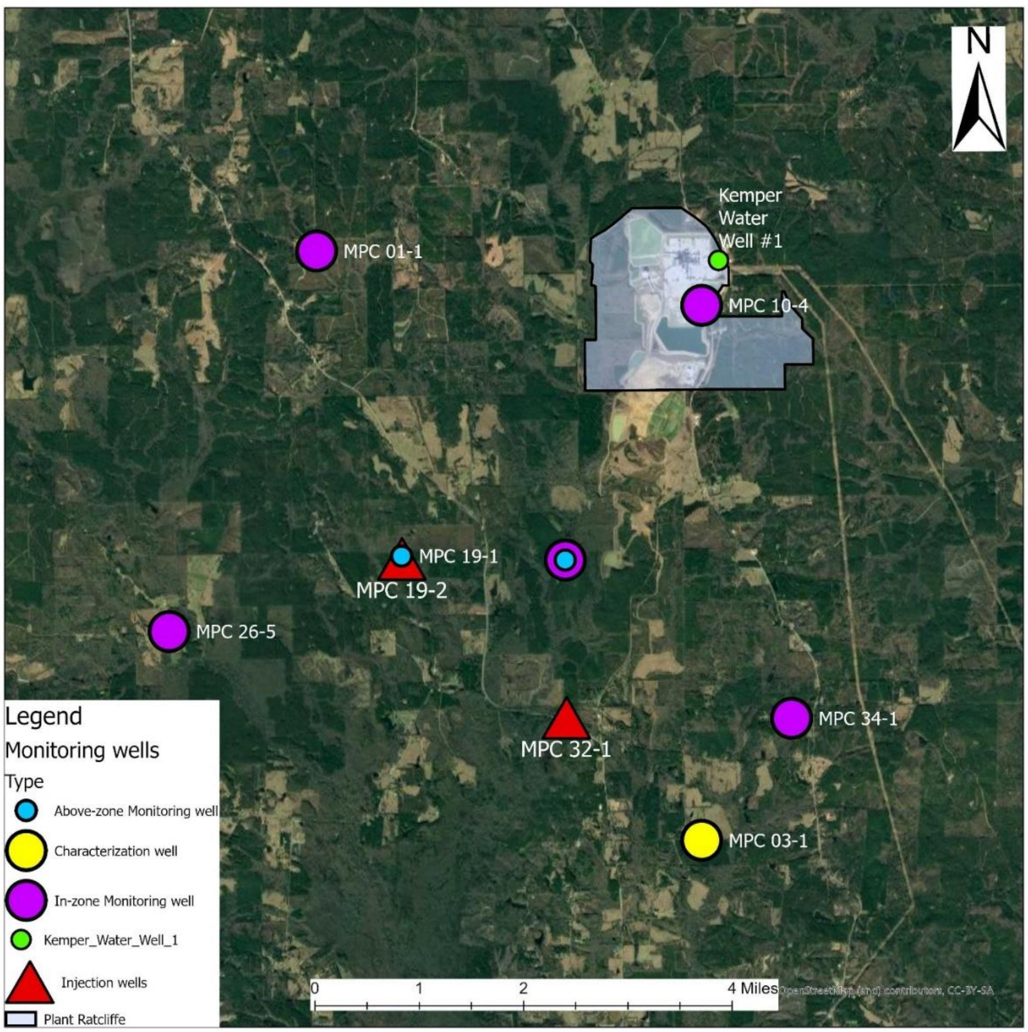

Figure 1: Kemper County Storage Complex regional project Map

The presence of faults and other structural features that could act as migration pathways for fluid was also reviewed on the seismic lines. None were found that would have an impact on the proposed injection activity. Section **B.1.b** of the *Application Narrative* discussed the structural setting and 2D seismic profile in more detail. The following is a short description of the geologic setting, lithology, stratigraphy and hydrology of the Kemper County Storage Complex. Please refer to the *Application Narrative* for a more detailed geologic description.

Kemper County is underlain by sedimentary rock of Cambrian through Tertiary age that is more than 26,000 feet thick and nonconformably overlies the Precambrian crystalline basement (Hale-Ehrlich and Coleman, 1993)[1]. Paleozoic strata range in age from Cambrian through Pennsylvanian and were deposited near the southern tip of a promontory of the ancestral North American continental platform, at what is now the buried juncture of the Appalachian and Ouachita tectonic belts (Thomas, 1977, 1988)[2]. A thick onlapping section of Mesozoic-Cenozoic sediments overlies the Paleozoic section with pronounced angular unconformity (Hale-Ehrlich and Coleman, 1993)[1]; (Pashin et al., 2008)[3]. The Mesozoic-Cenozoic strata were deposited in the Mississippi Embayment of the Gulf of Mexico Basin and form a southwest-dipping sedimentary wedge. These deposits range in age from Early Cretaceous at the base, to the Tertiary strata of the Naheola and Nanafalia Formations exposed at the surface. The Mesozoic-Cenozoic section is dominated by loosely consolidated sandstone, indurated to soft mudrock, chalk and marl. The injection and confining zones for the proposed Kemper County Storage Complex are within the Mesozoic-Cenozoic strata.

[1] Hale-Ehrlich, W. S., and Coleman, J. L., Jr., 1993, Ouachita-Appalachian juncture: a Paleozoic transpressional zone in the southeastern U.S.A.: American Association of Petroleum Geologists Bulletin, v. 77, p. 552-568.

[2] Thomas, W. A., 1977, Evolution of Appalachian-Ouachita salients and recesses from reentrants and promontories in the continental margin: American Journal of Science, v. 277, p. 1233- 1278.

[3] Pashin, J. C., Hills, D. J., Kopaska-Merkel, D. C., & McIntyre, M. R. (2008). Geological Evaluation of the Potential for CO2 Sequestration in Kemper County. *Mississippi: Birmingham, Final Report, Southern Company Research & Environmental Affairs*.

At the base of the Mesozoic section is a thin, sub horizontal limestone that is assigned to the Lower Cretaceous Mooringsport formation. Overlying the Mooringsport, the sandstones of the Lower Cretaceous Paluxy formation are the targeted CO_2 injection interval at the proposed Kemper County Storage Complex and have a shallow dip towards the southwest. The top of the Paluxy Formation occurs at a depth of approximately 5,040 ft in both proposed injection wells. Gross sand thickness of more than 500 feet (with net to gross ratios ranging from 0.74 to 0.86) is distributed between four main sandstone flow units. The sandstone layers are separated by shale and siltstone, which could serve as local, vertical confining units or flow barriers.

The primary confining zone above the injection zone is the Tuscaloosa Marine Shale which isolates USDWs in the upper Tuscaloosa and Eutaw formations from saline aquifers in the lower Tuscaloosa and Dantzler sandstones. Secondary confinement intervals include the Selma Group and Porters Creek clay, which isolate overlying Paleocene and Eocene freshwater aquifers of the Naheola and Nanafalia formations, the unnamed shale member of the middle Washita-Fredericksburg, which is located immediately above the Big Fred sand, and the unnamed basal shale member of the Washita-Fredericksburg group, which is located immediately above the Paluxy formation.

Figure 2 is a stratigraphic chart for the main Mesozoic and Cenozoic stratigraphic units at the Kemper County Storage Complex. The local freshwater aquifers and potential USDWs are indicated, as well as the proposed CO_2 storage reservoir and five confining units. Below the basal Mesozoic unconformity, a thick confining unit at the top of the Paleozoic section is expected to isolate underlying Paleozoic sediments from fluids contained in Mesozoic reservoirs.

System		Series		Stratigraphic Unit	Major Sub-Units	Potential Reservoirs and Confining Units	
Quaternary		Holocene		Alluvium		Shallow Alluvial Aquifers	
Tertiary	Paleogene	Eocene	Lower	Wilcox Group	*Undifferentiated*	Freshwater Aquifer	
		Paleocene	Upper		Nanafalia Fm.		
				Midway Group	Naheola Fm.	Freshwater Aquifer	
					Porters Creek Clay	Aquitard	
			Lower		Clayton Fm.		
Cretaceous		Upper		Selma Group	Owl Creek / Prairie Bluff Fm.	Aquitard	
					Ripley (McNairy) Fm.		
					Demopolis Fm.		
					Mooreville Fm.		
				Eutaw Group	Tombigbee Sand	USDW	
					McShann Fm.		
				Tuscaloosa Group	Upper Tuscaloosa (Gordo Fm.)	USDW	
					Tuscaloosa Marine Shale	Confining zone	
					Undifferentiated Lower Tuscaloosa Shale		
					Lower Tuscaloosa Massive Sand	**Saline Reservoir**	**INJECTION ZONE**
		Lower		Washita-Fredericksburg	Dantzler Fm.	**Saline Reservoir**	
					Undifferentiated Upper Shale	**Confinement Interval**	
					'Big Fred' Sand	**Saline Reservoir**	
					Undifferentiated Basal Shale	**Confinement Interval**	
				Paluxy Formation		**Injection Interval**	
				Mooringsport Formation		Limestone Marker	
Paleozoic Undifferentiated				Pennsylvanian Pottsville Fm?		Regional Confining Unit	

Figure 2: Cenozoic and Mesozoic Stratigraphic Units at Proposed Kemper County Storage Complex

The USDW aquifers within Kemper County reside in both Tertiary- and Upper Cretaceous-age clastic reservoirs. The Tertiary formations include the Middle and Lower Wilcox, the Naheola, and the Nanafalia Formations (**Figure 2**). The Middle and Lower Wilcox USDW aquifers have Total Dissolved Solids (TDS) of < 200 milligrams-per-liter (mg/L). The principal drinking water source for Kemper County comes from the Middle and Lower Wilcox Formation. Potable water at Plant Ratcliffe is provided by the Northwest Kemper Water Association which utilizes the Lower Wilcox as its source for drinking water. The Naheola and Nanafalia Formations are shallower than 600 feet in the area around the Storage Complex, and these formations receive meteoric recharge at the surface in northeastern Kemper County. Therefore, all active and potential aquifers of Tertiary age can be expected to be USDWs and must be protected. The Porters Creek clay and Selma Group together serve as an aquitard to separate the freshwater aquifers in the Tertiary from the Upper Cretaceous. The Upper Cretaceous contains the Eutaw-McShan, Gordo and Coker with potential USDW aquifers with TDS concentrations of 1,000 to 20,000 mg/L. The Eutaw-McShan aquifer is the deepest USDW in the Kemper County Storage Complex.

Water used for industrial purposes at Plant Ratcliffe (i.e., nonpotable) is sourced primarily as reclaimed water from two publicly owned treatment works (POTWs) nearby and is thus not related to USDWs. All reservoirs that qualify as USDWs will be monitored in the region for signs of contamination. The most likely indicators of groundwater impact from CO_2 leakage include: 1) an increase in TDS content if water with higher TDS migrated into overlying USDW and 2) a reduction in pH as CO_2 or carbonated brine results in an increase in dissolved carbonate. See **Section B.7** of the *Application Narrative* for more on the hydrogeology of the Kemper County Storage Complex.

Figure 1 provides a regional view of the proposed site for the Kemper County Storage Complex, which shows the following:

- Boundary of the 5,000-acre Plant Ratcliffe property owned by Mississippi Power Company proposed for the Kemper County Storage Complex;
- Location of Plant Ratcliffe;

- Location of the two proposed injection wells: MPC 19-2 and MPC 32-1;
- Location of proposed monitoring wells;
- Six characterization wells:
  - MPC 10-4 #1, MPC 26-5 #1 and MPC 34-1 #1, drilled in 2017 for Project ECO_2S
  - MPC 01-1 drilled in 2020
  - MPC 03-1 and MPC 19-1 drilled in 2021;
- MPC notes that one proposed injection well (MPC 19-2) will be drilled and completed on the same well pad as the MPC 19-1 well location, where the MPC 19-1 well will serve as an above-zone monitoring well. The location of the second proposed injection well (MPC 32-1) is planned to be located 2 miles to the southeast from MPC 19-1 and MPC 19-2.
- Kemper Water Well #1, a key sub-surface source of data;
- Locations of previously drilled deep wells used in the analysis of storage reservoir and confining unit properties.

A.2.b Operational Data

A.2.b.1 Operational Information

Details on the injection operation are presented in **Table 1**. A volume of 2.8 million metric tons of CO_2 per year will be injected into the Paluxy zones for 30 years. The CO_2 will be injected through two vertical injection wells with wellbore diameters of 4.5 inches. It is important to note that this AoR plan intends to serve as an attachment for the permit associated with the proposed MPC 19-2 well. The permit for the proposed MPC 32-1 well will be generated and submitted separately.

Table 1: Operating Details

Operating Information	Injection Well 1 (MPC 19-2)
Location (global coordinates) X Y	 32.6130560°N -88.806111°W
Model coordinates (ft) X Y	 97,805.1 952,905.6
No. of perforated intervals	1
Perforated interval (ft MSL) Z top Z bottom	 5,032 5,571
Injection well tubing diameter (in.)	4.5
Planned injection period Start: End:	 2025 2055
Injection duration (years)	30
Injection rate (t/day)*	3,895

A.2.b.2 Fracture Pressure and Fracture Gradient

The average minimum principal stress for the Paluxy formation was determined from the generation of a 1-D Mechanical Earth Model. For the entire storage zone, including reservoir and confining units, 90% of the mean formation fracture gradient ranges from 0.61 psi/ft to 0.65 psi/ft. More information on the calculated fracture pressure can be found in section B.5 of the *Application Narrative*. To ensure that fracture pressure is not surpassed during the simulation or during the actual injection of CO_2 in the field, a conservative bottomhole pressure limit of 2,900 psia (0.58 psi/ft at approximately 5,000 ft or 90% of an assumed fracture pressure gradient of 0.65 psi/ft) was imposed. For the reservoir simulation, the well was operated using this constraint, with an additional injection rate constraint of 75 million standard cubic feet per day.

Table 2: Injection Pressure Details

Injection Pressure Details	Injection Well 1
Fracture gradient (psi/ft)	0.65
Maximum injection pressure (90% of fracture pressure) (psi)	2,900
Elevation corresponding to maximum injection pressure (ft MSL)	5,000
Elevation at the top of the perforated interval (ft MSL)	5,034
Calculated maximum injection pressure at the top of the perforated interval (psi)	2,920

A.3 Model Development

A.3.a Conceptual Model of the Proposed Injection Site

For the Kemper County Storage Complex, two injection wells are planned to inject 75 MMscfd (3,890 metric tons per day) per well of CO_2 for 30 years. The sources of the carbon dioxide for the project are the natural gas-fired electrical generating stations at Plant Ratcliffe in Kemper County, Mississippi, and Plant Daniel located 150 miles south in Jackson County, Mississippi. The CO_2 will be supplied by pipeline to the injection site. The injection will be into the Lower Cretaceous Paluxy sandstone, a saline reservoir occurring at a depth of approximately 5,000 feet at the proposed injection site. The formation dips to the southwest and it is anticipated that the CO_2 will migrate up-dip towards the northeast. The Tuscaloosa Marine Shale, about 1,600 feet above the top of the Paluxy formation, serves as the primary confining unit. The Kemper County Storage Complex Conceptual Model is illustrated on **Figure 3**.

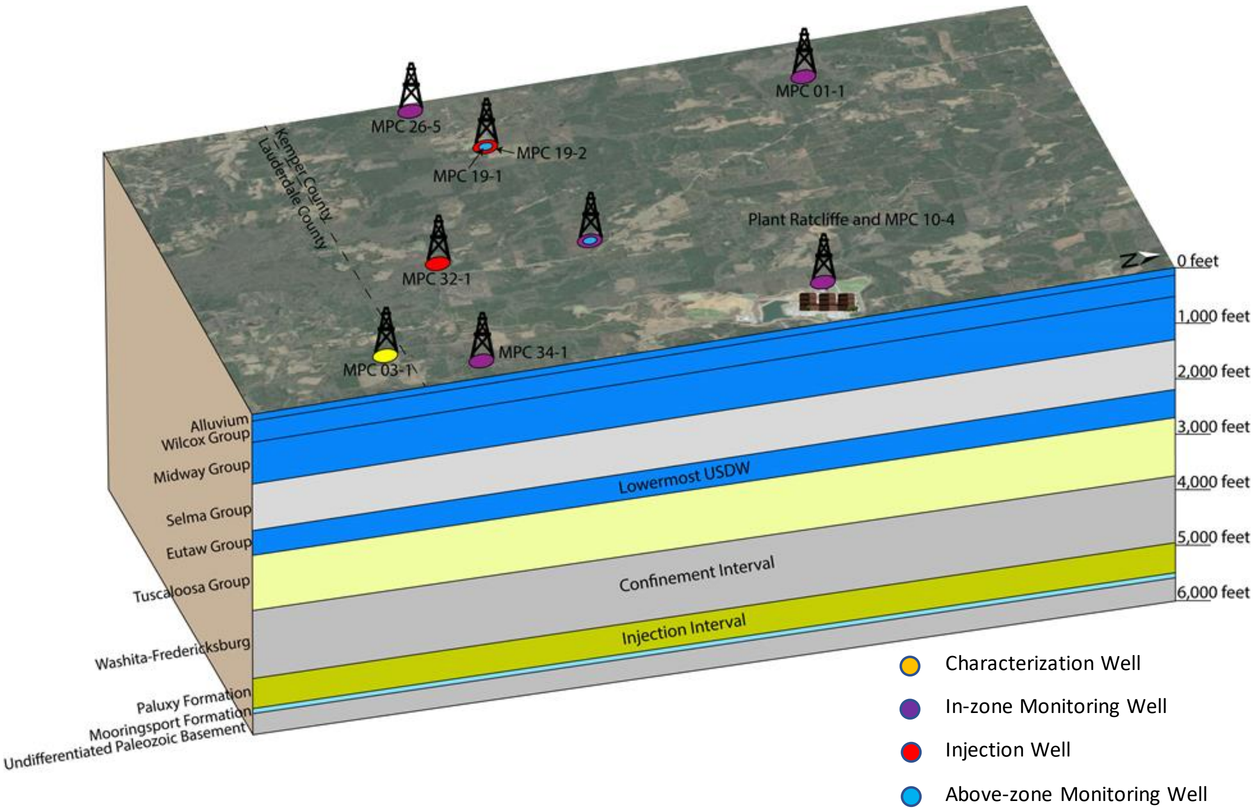

Figure 3: Kemper County Storage Complex Conceptual Model

A.3.b Determination of Physical Processes to be Included in the Computational Model

The details of MPC's computational modeling efforts are illustrated below in this section, which satisfy the requirement of 40 CFR 146.84(b). MPC will upload all relevant datasets in tabular format to the EPA's GSDT as they become available.

The Kemper County CO_2 storage model was constructed by Advanced Resource International, Inc at the request of Mississippi Power Company. The computational model, using the Computer Modeling Group's *GEM* simulator, was developed to model the subsurface injection and flow of CO_2 in the Paluxy formation in Kemper County, Mississippi. *GEM* is a reservoir simulator that uses an equation of state to simulate fully compositional reservoir flow and is used widely by industry for modeling the flow of three-phase, multi-component fluids. This tool can simulate the development of the CO_2 plume, and the associated pressure front, as well as assess the long-term fate of the injected CO_2. *GEM* has the capability to model CO_2 trapping, including residual gas trapping via relative permeability hysteresis, CO_2 dissolution into the aqueous phase and mineral trapping. The Kemper County CO_2 storage model is set up as a two-phase water/gas system.

All maps were generated using the North American Datum 1927 (NAD27) system and all maps in this section refer to X and Y coordinates in feet.

The following formulations and methods are employed in the software to model phase behavior and relationships:

- Peng-Robinson Equation of State to model gas and water phase behavior.
- CO_2 dissolution in water is modeled using Henry's solubility model, with Henry's constant as a function of temperature, pressure, and salinity (Li & Nghiem, 1986)[4].
- Brine viscosity is calculated using the correlation developed by Kestin, Khalifa and Correia as a function of pressure, temperature, and salinity (Kestin, Khalifa, & Correia, 1981)[5].
- Brine density is calculated from the Rowe-Chou correlation (Rowe & Chou, 1970)[6].
- CO_2 trapping due to hysteresis is modeled using Land's correlation to determine the imbibition gas relative permeability curve as a function of the given drainage curve (Land, 1968)[7].

The methods and correlations mentioned above are used to ensure accurate

[4] Li, Y.; Ngheim, L. X. Phase equilibria of oil, gas and water/brine mixtures from a cubic equation of state and Henry's law. Can. J. Chem. Eng. 1986, 64, 486-496.

[5] Kestin, J. Khalifa, H. Correia, R. 1981. Tables of the Dynamic and Kinematic Viscosity of Aqueous NaCl Solutions in the Temperature Range 20-150C and the Pressure Range 0.1-35MPa. J. Phys. Chem. Ref. Data Vol. 10, No. 1.

[6] Rowe, A.M. and Chou, J.C.S., Pressure-Volume-Temperature-Concentration Relation of Aqueous NaCl Solutions, J. Chem. Eng. Data, Vol. 15, (1970), pp. 61-66

[7] Land, C.S. 1968. Calculation of Imbibition Relative Permeability for Two- and Three-Phase Flow From Rock Properties. SPE J. 8 (2): 149–156. SPE-1942-PA.

phase property calculations, such as brine density due to CO_2 dissolution, brine solubility, and CO_2 trapping due to hysteresis. Multiphase flow (gas/water) and buoyancy/gravity processes are modeled. These processes were included in the simulation model because they are important aspects of CO_2 sequestration into saline formations, where CO_2 dissolution in brine and CO_2 trapping due to hysteresis play a major role in immobilizing the CO_2 plume. Another CO_2 storage method involves mineral trapping. Mineral trapping is the permanent sequestration of CO_2 through chemical reactions with dissolved minerals in the reservoir brine and with the minerals in the reservoir rock itself. However, the mineral trapping mechanism is slow and is expected to occur over very long time periods, perhaps centuries. Through field studies and numerical modeling, it has been determined that CO_2 is primarily trapped through precipitation of calcite ($CaCO_3$), siderite ($FeCO_3$), dolomite ($CaMg(CO_3)_2$) and dawsonite ($NaAlCO_3(OH)_2$). In order for mineral trapping through carbonate precipitation to occur, primary minerals rich in Mg, Fe, Na and Ca, such as feldspars and clays, must be present. Therefore, immature sandstones having an abundance of fresh rock fragments (unweathered igneous and metamorphic minerals and clays rich in Mg, Fe and Ca) are most effective[8]. The abundance and ratios of these primary minerals can have a tremendous effect on the type of secondary minerals that are precipitated as well as on the overall total amount of CO_2 sequestered through mineral trapping. Mineral trapping results in a decrease in porosity (shown to be up to 3 percent in laboratory tests), which also has an effect on permeability (shown to be a reduction of up to 7 percent in laboratory tests)[9]. However, the rates of chemical reactions in question are so slow that it is unlikely to affect injection of CO_2 into the reservoir. The

[8] Bachu, S., Gunter, W.D., and Perkins, E.H., “Aquifer disposal of CO2: hydrodynamic and mineral trapping,” Energy Convers. Mgmt., v. 35 p. 269-279. 1994.

[8] Pruess, K., Xu, T., Apps, J. and Garcia, J., “Numerical Modeling of Aquifer Disposal of CO2,” SPE paper 66357 presented at the SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, Texas, 26-28, February 2001

[8] Xu, T., Apps, J. A., and Pruess, K., Reactive geochemical transport simulation to study mineral trapping for CO2 disposal in deep saline arenaceous aquifers, Lawrence Berkeley National Laboratory Report LBNL-50089, Berkeley, California, 66 pp., 2002.

[9] Kaszuba, John P., Janecky, David R., and Snow, Marjorie G., 2002, Experimental evaluation of mixed fluid reactions between supercritical carbon dioxide and a NaCl brine: Relevance to geologic aquifer carbon sequestration: Geological Society of America, Abstracts with Programs, v. 34, no. 6, #135-3, p. 304

mixing and diffusion of the CO_2 plume will, however, be affected during the centuries following injection[10]. **Figure 4** [11], showing the contribution of each trapping mechanism, suggests that mineralization affecting porosity and permeability of the reservoir will not have an impact during the timeframe of this sequestration project as it takes hundreds or even thousands of years for mineralization to become significant Therefore, mineralization of the injected CO_2 is not currently considered in the model.

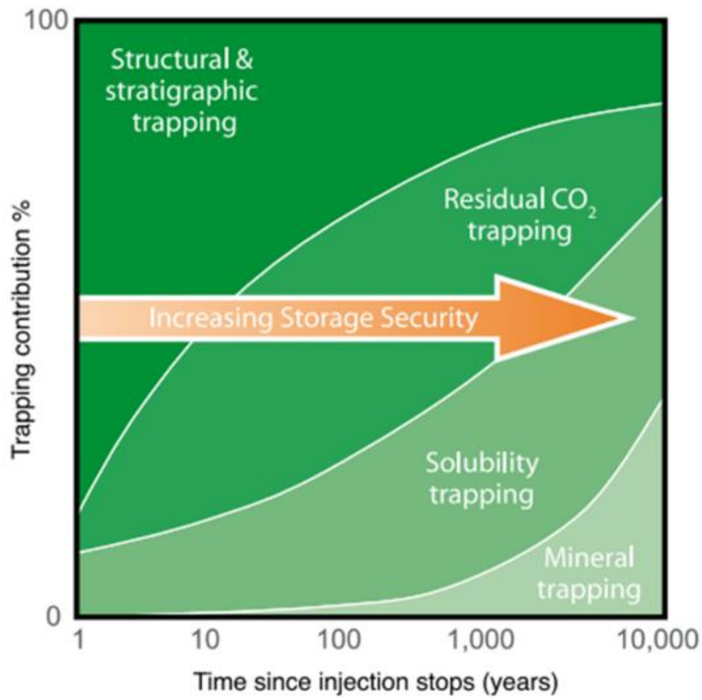

Figure 4: Trapping Mechanisms Contribution Over Time

A.3.c Computational Model Design

A.3.c.1 Computational Code Determination

The Computer Modeling Group's reservoir simulator *GEM* is used for all the simulation work conducted in support of this permit application. *GEM* is an industry standard Equation of State reservoir simulator for compositional, chemical and unconventional reservoir modeling that is fully capable of accurately modelling the long-

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10 Pruess, K., Xu, T., Apps, J. and Garcia, J., "Numerical Modeling of Aquifer Disposal of CO_2," SPE paper 66357 presented at the SPE/EPA/DOE Exploration and Production Environmental Conference, San Antonio, Texas, 26-28, February 2001

11 IPCC Special Report on Carbon Dioxide Capture and Storage,

term effects of CO_2 injection into saline reservoirs. Refer to section A.3.b for a full description of all the processes included in *GEM*.

A.3.c.2 Model Spatial Extent, Discretization, and Boundary Conditions

A.3.c.2.1 Model Domain and Discretization

The model uses a rectangular tartan grid system (smaller grid blocks in the area of the wells with larger grid blocks further away from the wells) with 150 grid cells in the x-direction and 165 grid cells in the y-direction. Individual grid blocks around the injectors are 400 ft by 400 ft, while grid blocks further away are 2,000 ft by 2,000 ft (**Figure 5)**. Geologic properties (depth, thickness, permeability, and porosity) are assigned for each grid cell to reflect the subsurface characteristics discerned from the geologic assessment. Top depth maps are imported into the simulation model from Petra. Grid depths are then internally calculated from the depth mpas. Thickness values are internally calculated for each cell by subtracting the top depth of the cell and the top depth of the cell below it. Uniform porosity and permeability values are assigned to each grid layer based on the process described in the Conceptual Modeling document.

The model dimensions are 32.2 miles in the dip direction and 26.5 miles along strike, and covering an area of more than 850 square miles (545,000 acres). Because it wass demonstrated that the CO_2 will move up-dip, the model was intentionally off-center to cover a larger area up-dip from the wells. **Figure 6** shows the model boundary on a site area map.

Due to the extensive thickness of the Paluxy formation, each of the four Paluxy zones were vertically subdivided into 5 layers to achieve a better resolution of the CO_2 plume extent and to model buoyancy effects. This resulted in 20 sub-layers in the Paluxy with thicknesses ranging from approximately 10 feet to 20 feet. As a result, the model has a total of 28 layers in the vertical direction, for a total of 693,000 grid blocks. The interbedded shale layers within the Paluxy formation, that potentially serve as barriers between each unit of Paluxy sandstone, were not modeled as individual layers but a zero vertical transmissibility factor was implemented to implicitly model these baffles. Sensitivity analysis of the transmissibility multiplier showed no significant change in the plume behavior. The shale barrier at the top of the Paluxy zone was modeled explicitly without a zero vertical transmissibility.

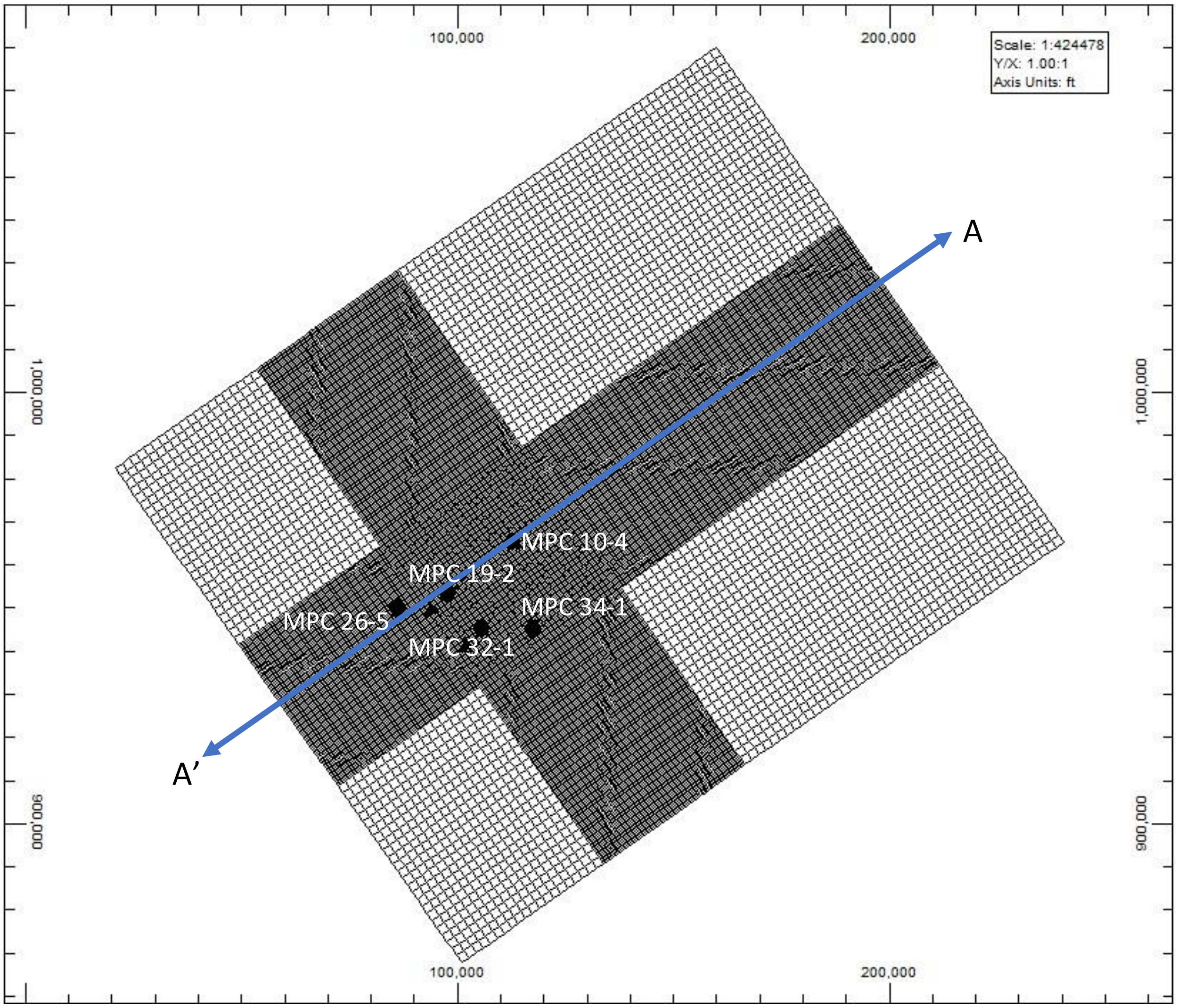

Figure 5: Top View of the Model Area

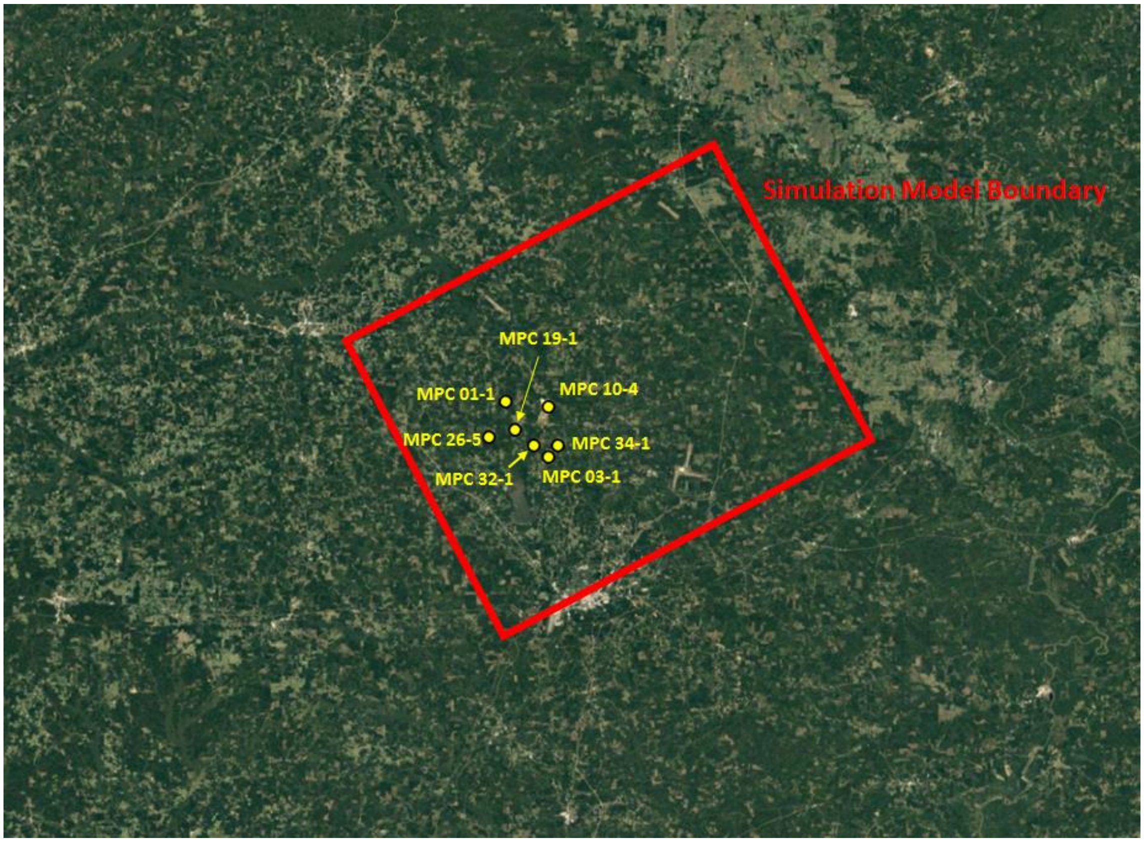

Figure 6: Simulation Model Boundary on Site Area Map

Figure 7 shows a cross section of the reservoir model, highlighting the injection interval, the primary confining unit (Marine Tuscaloosa Shale) and the vertical resolution of the model.

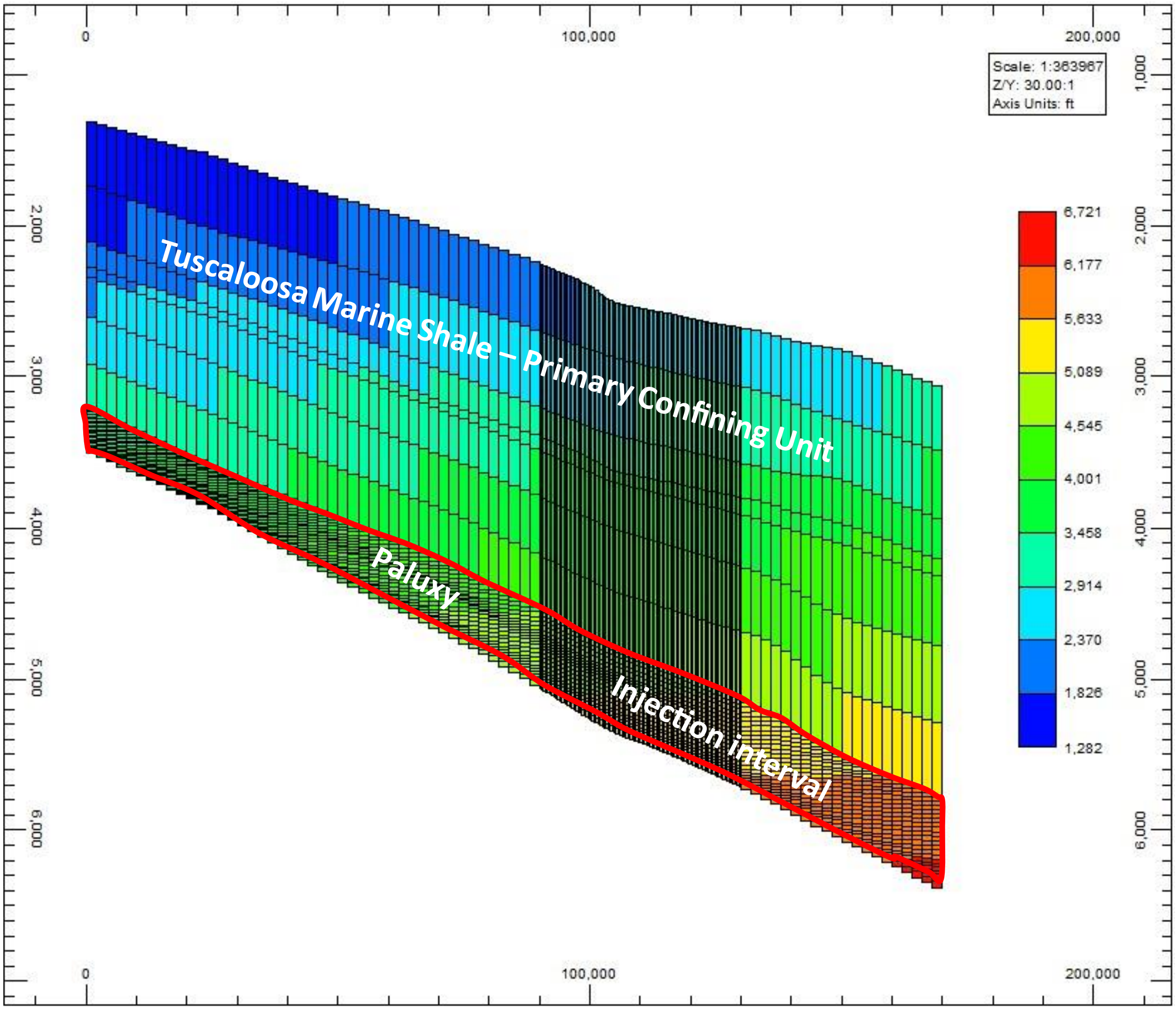

Figure 7: Side View Map of the Reservoir Model (30:1 aspect ratio)

An understanding of the regional and local subsurface geology is essential to accurately assess the injection reservoir and model the subsurface injection and flow of CO_2. Based upon interpretation and evaluation of geophysical well logs, core analysis and 2D seismic analysis, a comprehensive picture of the subsurface geology has been developed for the Kemper County Storage Complex (see *Application Narrative*). Once the range of geologic parameters was established, conservative values were used in the reservoir simulation model to estimate fluid flow, pressure, and CO_2 storage processes. These parameters (elevation, thickness, porosity, permeability, etc.) are detailed in upcoming sections. The model domain information is summarized in **Table 3**.

Table 3: Model Domain Information

Coordinate System	North American Datum 1927 (NAD27)		
Horizontal Datum	(KG0640) MEADES RANCH		
Coordinate System Units	US FEET		
Zone	Clarke 1866		
FIPSZONE	2301	**ADSZONE**	4351
Coordinate of X min	20,787	**Coordinate of X max**	240,624
Coordinate of Y min	866,553	**Coordinate of Y max**	1,079,220
Elevation of bottom of domain	6,721 feet	**Elevation of top? of domain**	1,282 feet

As detailed in the *Application Narrative*, four individual Paluxy Sandstone zones were identified as potential storage reservoirs for CO_2. The average depth (measured depth from MPC 26-5, MPC 34-1 and MPC 10-4), average thickness and net to gross ratio of the total 12 modeled formations (over the extent of the model) are tabulated in **Table 4**, Including the four Paluxy Sandstone zones, where CO_2 will be injected. Isopach and elevation maps for the 12 horizons were generated using the *Petra*™ software suite and were directly input to the simulation model. **Figures 8a and 8b** are an illustration of the elevation for the top Paluxy sandstone and total thickness map for the Paluxy Formation. All maps were generated using the North American Datum 1927 (NAD27) system so all maps in this section have X and Y coordinates in feet.

Table 4: Model Elevation, Thickness, and Net to-Gross-Ratio Per Formation

Flow Unit	Average Top MD (ft)	Thickness (ft)	Net to Gross Ratio
Upper Tuscaloosa	2,576	530	1
Marine Tuscaloosa	2,960	369	1
Massive Sand	3,470	231	0.96
Dantzler	3,705	101	0.98
Upper Washita Fredericksburg	3,796	336	1
Big Fred	4,138	415	0.90
Lower Washita Fredericksburg	4,552	395	1
Paluxy Zone 4	4,956	192	0.78
Paluxy Zone 3	5,130	100	0.76
Paluxy Zone 2	5,236	165	0.86
Paluxy Zone 1	5,396	106	0.74
Mooringsport	5,503	26	1

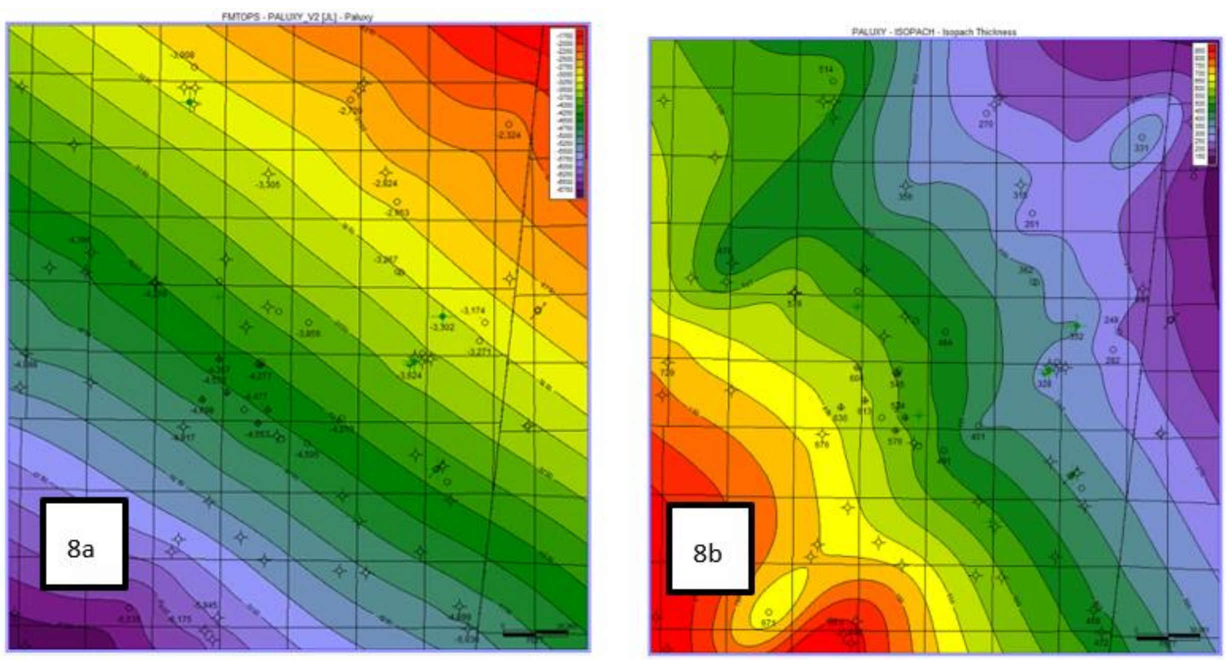

Figure 8: Petra Elevation Map of Paluxy (a) and Paluxy Thickness Map (b)

A.3.c.2.2 Boundary Conditions

The model was designed as an open boundary system as there are no geological or petrophysical features to act as fluid or pressure propagation boundaries in the model area (see section 1.2 of the *Application Narrative*). A pore volume multiplier of 1,000 was applied to each of the cells within the model to approximate an open-boundary system behavior. These modifiers can be used to adjust pore volumes if a reservoir boundary intersects a grid block, thereby isolating a portion of the grid block outside of the reservoir. This approach was chosen over the use of analytical aquifers, which are limited in application to fresh-water systems in the model.

A.3.c.3 Model Timeframe

According to the Class VI rules, the model needs to run from the beginning of injection activities until the plume movement ceases or until the pressure differential sufficient to lift fluids to the USDW is no longer present. The modelling was conducted for a total of 180 years, with the first 30 years covering injection and the following 150 years covering the monitoring period.

A.3.c.4 Parameterization

A.3.c.4.1 Porosity and Permeability

Saline Reservoirs Porosity

This section includes porosity information for all the sandstone formations. For the non-injection sandstones, porosity values were derived in each formation using an average of the the neutron porosity (NPHI) and density porosity (DPHZ) logs at each of the MPC 26-5, MPC 34-1 and MPC 10-4 wells. The values range from 27% to 35% and are summarized in **Table 5**.

Table 5: Non-injection Zones Saline Reservoirs Porosity Estimates Summary

Hydrogeologic Unit	Porosity (fraction)			
	MPC 26-5	MPC 34-1	MPC 10-4	Average
Massive Sand	0.29	0.30	0.31	0.30
Dantzler	0.32	0.35	0.33	0.33
Big Fred	0.28	0.27	0.27	0.27

Porosity values in the Paluxy formation were derived using an average of the neutron porosity and density porosity logs at the MPC 19-1 well. For better description of the CO_2 plume, each of the four Paluxy zones was further sub-divided into 5 layers of equivalent thickness. The corresponding porosity values range from 15.3% to 29.8% and are summarized in **Table 6** for all sub-layers of the four Paluxy zones. For more detailed information on the generation of porosity for each formation, refer to the *Conceptual Model* report.

Table 6: Injection Zone Porosity Estaimtes Summary

Hydrogeologic Unit	Porosity (fraction)				
	Sublayer 1	Sublayer 2	Sublayer 3	Sublayer 4	Sublayer 5
Paluxy Zone 4	0.252	0.206	0.255	0.259	0.221
Paluxy Zone 3	0.285	0.269	0.231	0.280	0.298
Paluxy Zone 2	0.212	0.159	0.196	0.243	0.193
Paluxy Zone 1	0.153	0.204	0.260	0.287	0.257

<u>Baffles Porosity</u>

Core was recovered from well MPC 10-4 and routine core analysis was performed on the mudstones in the Paluxy Formation as well as the Marine Tuscaloosa Shale. However, these reported porosities are not consistent with observations of the mudstone from Scanning Electron Microscopy images which indicated significant destressing and desiccation of the rock samples as a result of core retrieval, preparation, and storage. In light of the changes that occur to rock samples during coring procedures, an average porosity of 10% was applied to the mudstone intervals (non-sand)in the model. A cross-section of the reservoir model is shown in Error! Reference source not found.**9**, highlighting the porosity variation between formations.

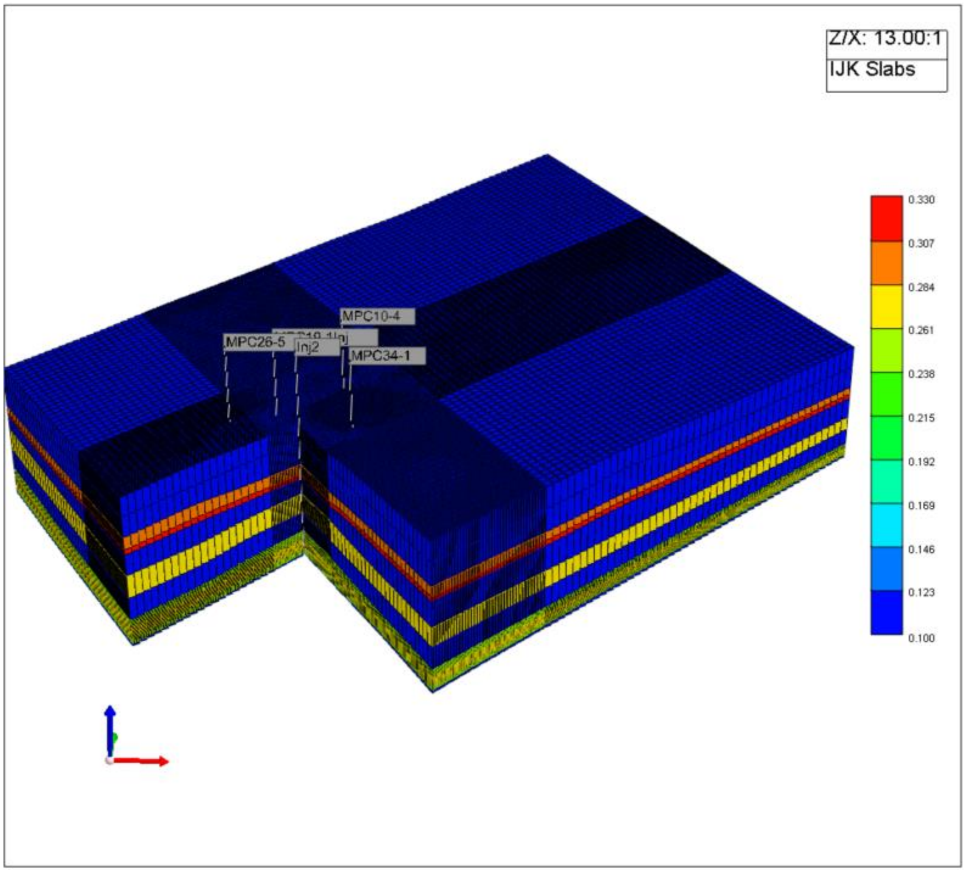

Figure 9: Kemper Reservoir Model Porosity (fraction) Variation Between Formations

Saline Reservoirs Permeability

For each target formation, permeability-porosity correlations were developed using the collected log data as well as available core data. These curves are shown in **Figure 10** for the four sandstone groups. The creation of these correlations is explained in detail in the *Conceptual Model* report. These transform functions are used to calculate the average horizontal permeability within each reservoir, assuming isotropic permeability. A 10:1 horizontal to vertical permeability ratio was then used to calculate the vertical permeability from the geometric average of the horizontal permeability. Horizontal permeability values are summarized in **Table 7** for the non-injection sandstones and **Table 8** for the Paluxy Sandstone.

Table 7: Non-injection Sandstones' Permeability Estimates

Hydrogeologic Unit	Horizontal Permeability (mD)			
	MPC 26-5	MPC 10-4	MPC 34-1	Average
Massive Sand	2,796	3,998	3,353	3,347
Dantzler	3,130	3,824	5,608	4,064
Big Fred	1,486	1,171	1,171	1,268

Table 8: Injection Zone (Paluxy) Horizontal Permeability Estimates

Hydrogeologic Unit	Horizontal Permeability (mD)				
	Sublayer 1	Sublayer 2	Sublayer 3	Sublayer 4	Sublayer 5
Paluxy Zone 4	1,874	738	1,999	2,150	1,018
Paluxy Zone 3	3,337	2,559	1,255	3,066	4,120
Paluxy Zone 2	855	226	594	1,595	545
Paluxy Zone 1	186	714	2,186	3,425	2,055

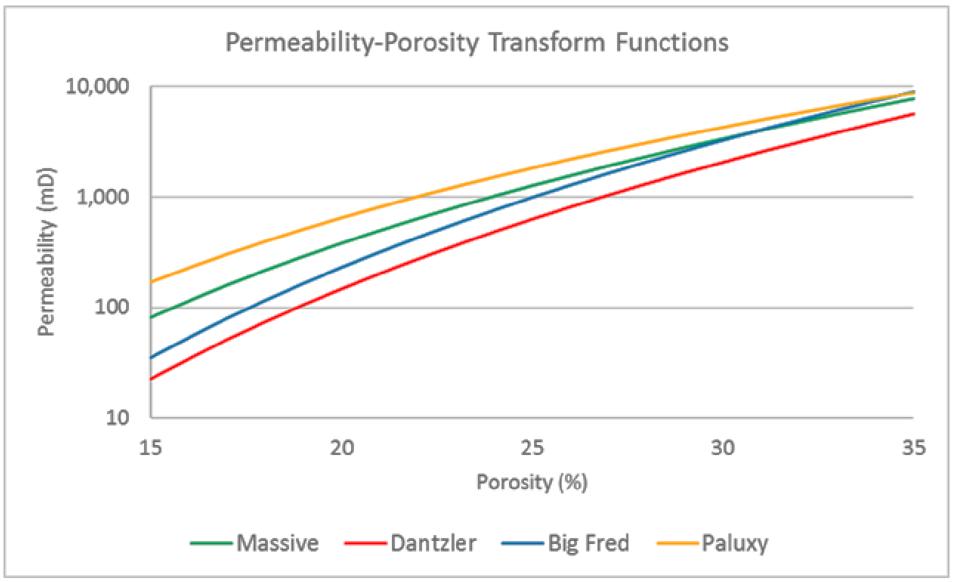

Figure 10: Kemper County Storage Complex Model Permeability-Porosity Transform Functions

<u>Baffles Permeability</u>

Pulse decay permeability measurements were carried on the Tuscaloosa Marine Shale, Paluxy, and Washita Fredericksburg formations. Based on the measurement from the shale intervals, a constant value of 50 nD was applied to all the confining units. More details are provided in the *Conceptual Model* report. A cross section of the reservoir model is shown in Error! Reference source not found.**11**, highlighting the permeability variation between formations.

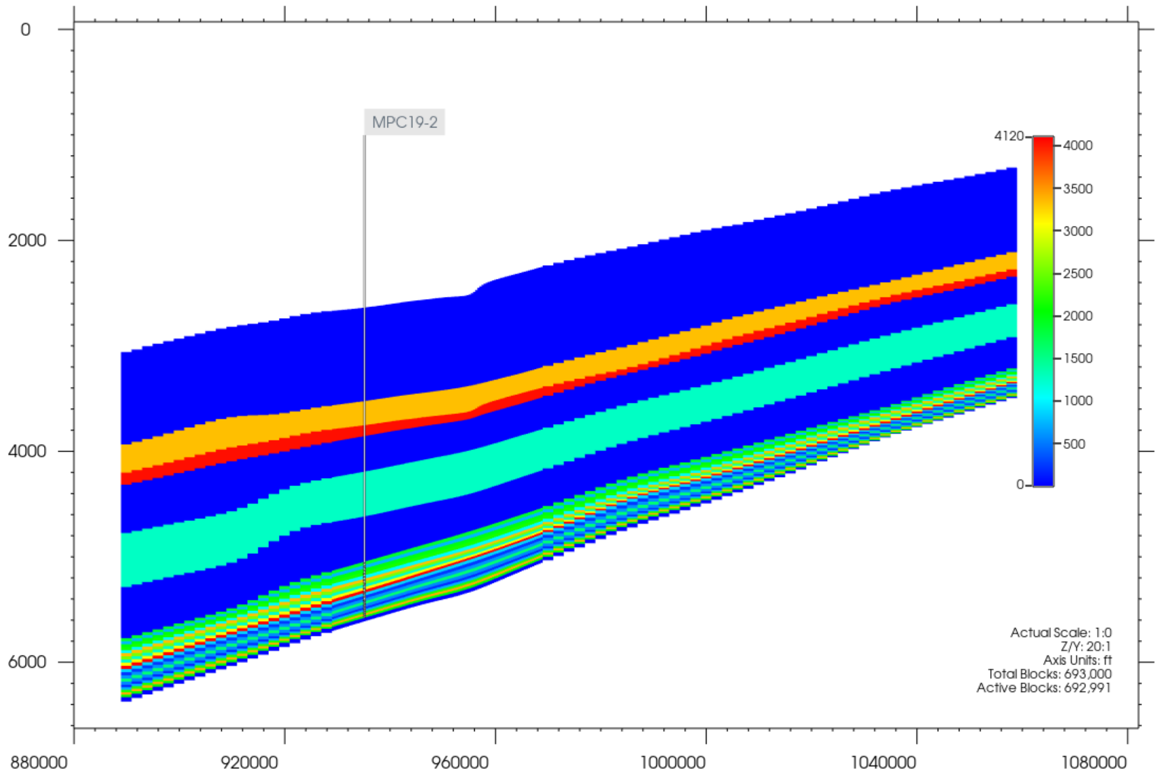

Figure 11: Side view of the KemperCounty Storage Complex Model Permeability (in millidarcies) Variation

Geologic strata below the confining unit uniformly dip to the southwest at about less than a degree. Since elevation maps were included in the model, a rigorous description of the dip and its subtle changes is included into the model.

A.3.c.5 Constitutive Relationships and Other Rock Properties

A.3.c.5.1 Relative Permeability Curves

The relative permeability data used for this study were based on work conducted in the Paluxy formation at the Anthropogenic Test Site at Citronelle, Alabama[12]. These analog curves were generated through history matching the CO_2 injection history pressure and CO_2 breakthrough response at multiple monitoring well locations.

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[12] ARI – Special Topical Report, 2013. Report of Advanced Core Analyses: Relative Permeability and Permeability vs. Throughput for Citronelle SECU D-9-8 #2

Based on literature research regarding drainage and imbibition CO_2/brine relative permeability curves [13] [14], the maximum relative permeability to gas was lowered from 1 to 0.65. The resulting curves are shown on **Figure 12**. While relative permeability measurements were carried out on Paluxy cores at the University of Wyoming, they were not deemed to be representative for this work. A detailed explanation is available in the *Conceptual Model*.

Relative permeability data was not available for the confining units at the Kemper County Store Complex. The relative permeability curves used were from the Calmar formation of the Alberta Basin, reported by Bennion and Bachu, 2007[15]. The Calmar formation was chosen as a proxy because its properties (salinity and pressure gradient for example) are similar to the properties at this study area. This set of curves represent a very low permeability shale rock with high irreducible water saturation and very low gas relative to permeability. Relative permeability curves for the confining units are illustrated on **Figure 13**.

[13] Bachu, Stefan. 2011. Drainage and Imbibition CO_2/Brine Relative Permeability Curves at In-situ Conditions for Sandstone Formations in Western Canada. GHGT 11, Kyoto, Japan.

[14] Krevor, S. Pini, R. Zuo, L. Benson, S. 2012. Relative Permeability and Trapping of CO_2 and Water in Sandstone Rocks at Reservoir Conditions. Water Resources Research, Volume 48, W02532.

[15] Bennion, B. D., & Bachu, S. (2007). Permeability and relative permeability measurements at reservoir conditions for CO_2-Water systems in ultra low permeability confining caprocks. Society of Petroleum Engineers.

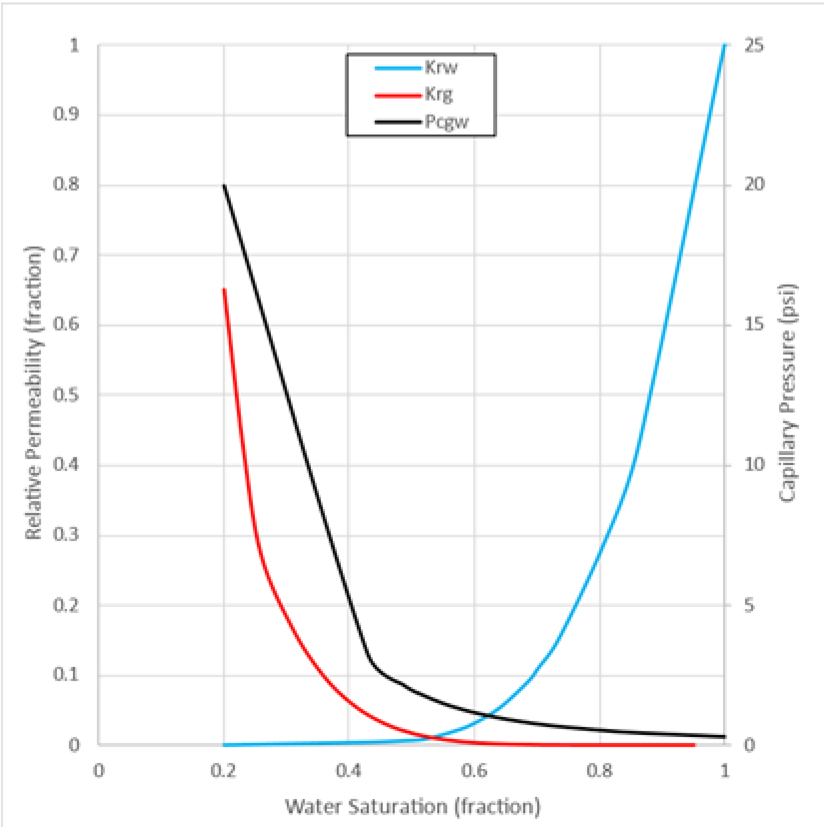

Figure 12: Kemper Model Sandtone Relative Permeability Curves

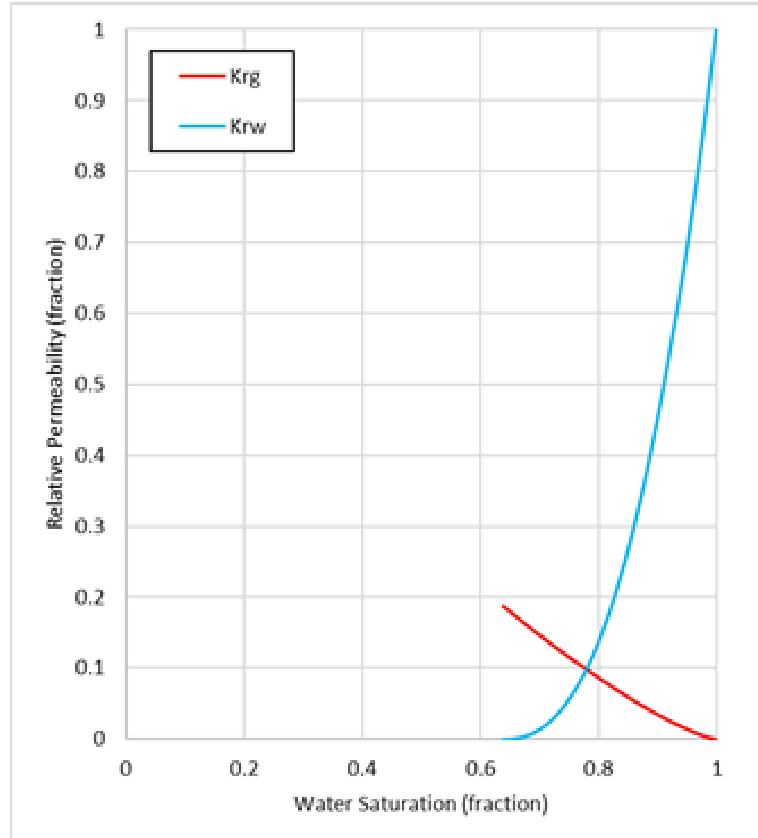

Figure 13: Kemper Model Confining Unit Relative Permeability Curves

A.3.c.5.2 Capillary Pressure

Shale capillary pressure curves show very high capillary entry pressure values (over 700 psi from 23 samples in the Tuscaloosa Marine Shale and 8 in the Lower Tuscaloosa Shale) (Lohr and Hackley, 2018[16]). These high entry capillary pressures mean that the CO_2 pressure in the injection zone needs to exceed these values to enter the 100% brine saturated caprock pores. As a conservative approach, capillary pressures are excluded for the shale layers to allow CO_2 migration into the caprock with the smallest pressure increase. However, because of the very low permeability of the shale layers, CO_2 stays within the Paluxy Formation and does not migrate into the Lower Washita-Fredericksburg Shale.

Rock Compressibility

The Hall correlation (Hall, 1953)[17] was used to compute the rock compressibility of the Paluxy Sandstone, which is shown below.

$$c_f = \left(1.782/\phi^{0.438}\right)10^{-6}$$

The correlation is based on laboratory data and is considered reasonable for normally pressured sandstones. With porosity in the Paluxy varying from 15.3% and 29.8%, the corresponding compressibility varies between 3.03e-6/psi and 4.05e-6 /psi with a weighted average of 3.3e-6/psi. As such, a value of 3.3e-6/psi was implemented in the model.

Initial Conditions

<u>Initial Reservoir Pressure</u>

The pressure gradient at the Kemper site is 0.427 psi/ft, or normally pressured, based on seven different measurements that are summarized in **Table 9**.

[16] Celeste D. Lohr and Paul C. Hackley (2018), Using mercury injection pressure analyses to estimate sealing capacity of the Tuscaloosa marine

[17] Hall, Howard N., 1953. Compressibility of Reservoir Rocks. J Pet Technol 5 (1953): 17–19. doi: https://doi.org/10.2118/953309-G

Table 9: Reservoir Pressure Gradient Estimates

Hydrogeologic Unit	Pressure Gradient (psi/ft)	Source
Tuscaloosa (Massive Sand)	0.436 psia/ft	Water analysis – Kemper County well - 2008
Tuscaloosa (Massive Sand)	0.498 psia/ft	Water analysis – Water well #1 – May 2018
Washita Fredericksburg	0.433 psia/ft	MPC 34-1 Pressure Falloff Test – April 2018
Washita Fredericksburg	0.400 psia/ft	MPC 34-1 Pressure Falloff Test – April 2018
Washita Fredericksburg	0.386 psia/ft	MPC 34-1 Water Sample – April 2018
Paluxy	0.410 psia/ft	MPC10-4 Pressure Falloff Test – June 2019
Paluxy	0.424 psia/ft	MPC 10-4 Water Sample – June 2019

Reservoir Temperature

Formation temperatures were reported for different reservoirs at the Water Well No. 1, MPC 34-1, and MPC 10-4 wells during fluid sampling operations conducted from June 2018 through August 2019. These temperatures are summarized in **Table 10**. The temperatures and their reference depth were directly input into the simulator. The simulator then automatically computed the corresponding temperature gradient and applied it to the full thickness of the reservoir.

Table 10: Kemper County Storage Complex Reservoir Temperatures

Hydrogeologic Unit	Sample	Depth (feet)	Temperature (F)	Temperature Gradient (°/100ft)
Lower Tuscaloosa	201801592-01	2,841	100	1.43
Washita Fredericksburg	201801231-05	4,470	125	1.45
Paluxy	201901859-01	5,183	128	1.31

Water Salinity

Several water samples were available at the water well #1 in the Lower Tuscaloosa, at the MPC 34-1 well in the Big Fred sandstones and at the MPC 10-4 well in the Paluxy sandstones. These are summarized in **Table 11** and were directly input into the model. More details regarding the fluid sampling operations are available in the Conceptual Model report.

Table 11: Kemper County Storage Complex Formation Water Salinities

Hydrogeologic Unit	Sample	TDS (mg/l)	TDS (ppm)	Source
Lower Tuscaloosa	201801592-01	18,791	18,567	Water Well No 1 Analysis
Washita Fredericksburg	201801231-05	85,271	80,587	MPC34-1 Water Analysis
Washita Fredericksburg	201801231-06	86,430	81,779	MPC34-1 Water Analysis
Paluxy	201901859-01	115,531	107,196	MPC10-4 Water Analysis

A.3.d Executing the Computational Model

A.3.d.1 Predictions of System Behavior

As a result of the high transmissivity of the Paluxy Formation and its large extent, the resultant simulation model indicates very little pressure gain in the reservoir and a rapid return to near native pressure after the injection operations are completed. Error! Reference source not found.**14** exhibits a map of the pressure buildup (pressure at the end of injection minus initial pressure) in the top sand layer at the end of the 30-year injection. The maximum reported pressure increase is 84 psi or less than 4% of native pressure. The pressure quickly returns to initial conditions , the maximum pressure increase already down to approximately 2% of initial pressure only one year after the end of injection, **Figure 15**. During the post injection period, reservoir pressure continues to drop and approaches the original reservoir pressure (**Figure 16**).

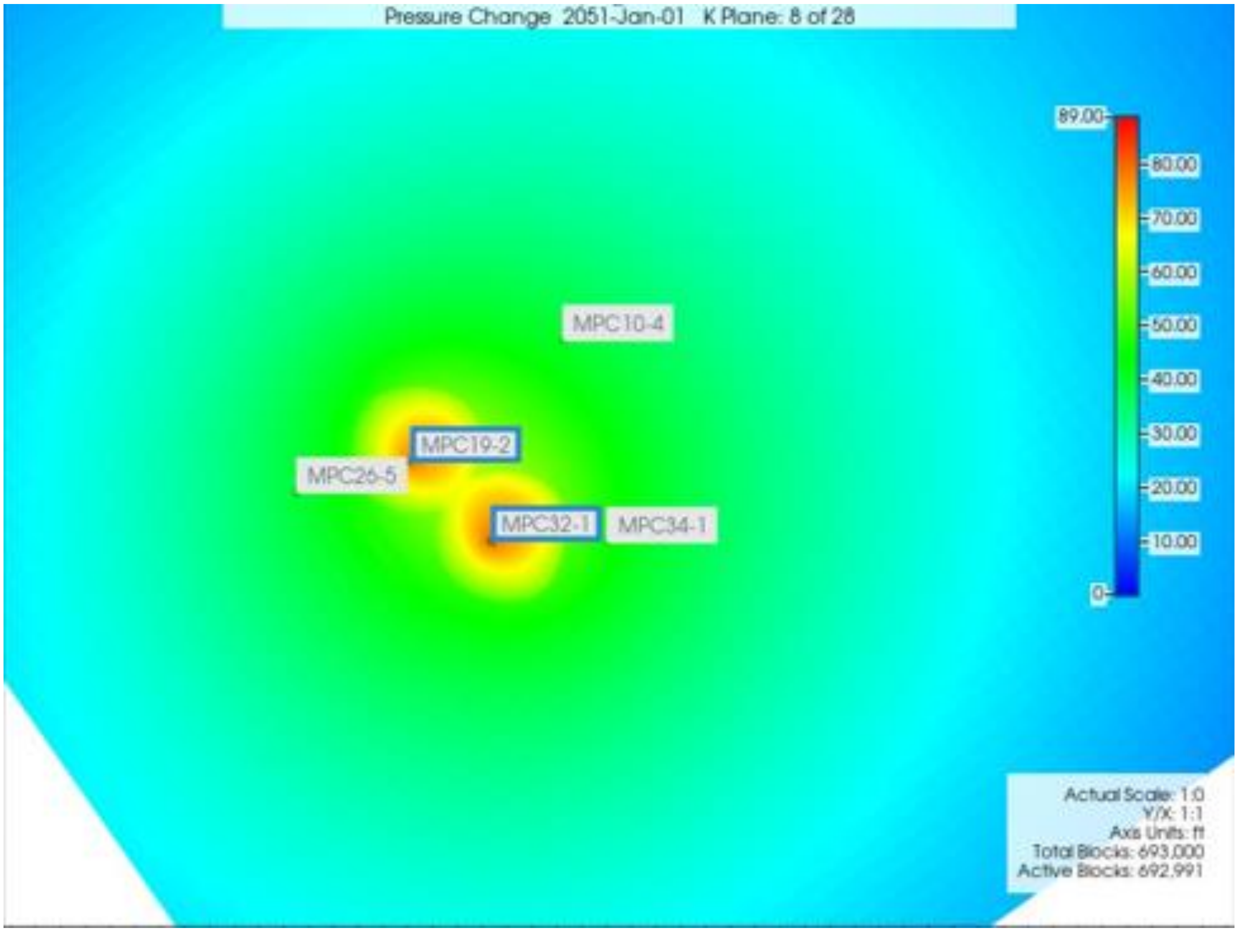

Figure 14: Pressure Increase from Initial Conditions at the End of Injection (in psi)

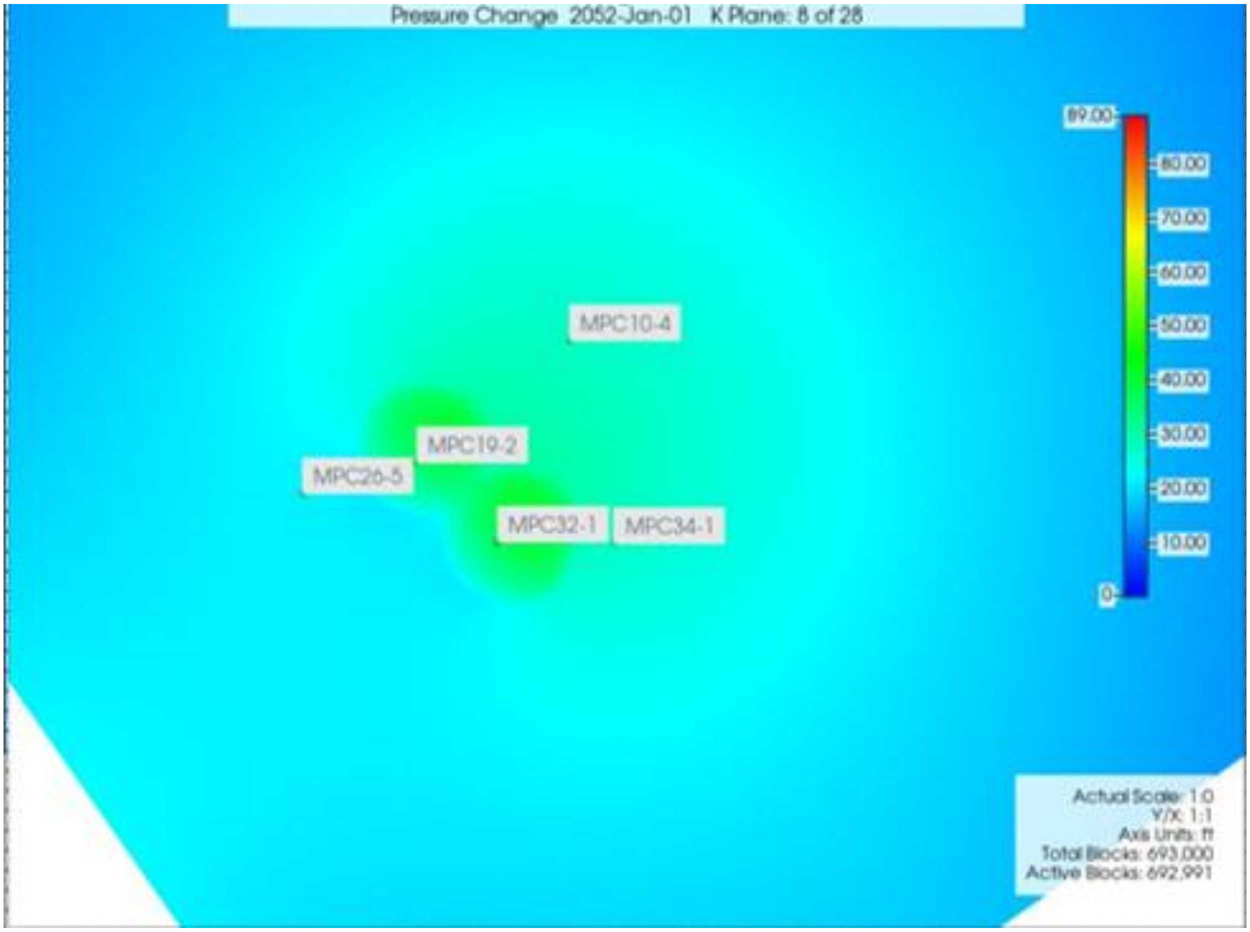

Figure 15: Pressure Buildup One Year after the End of Injection

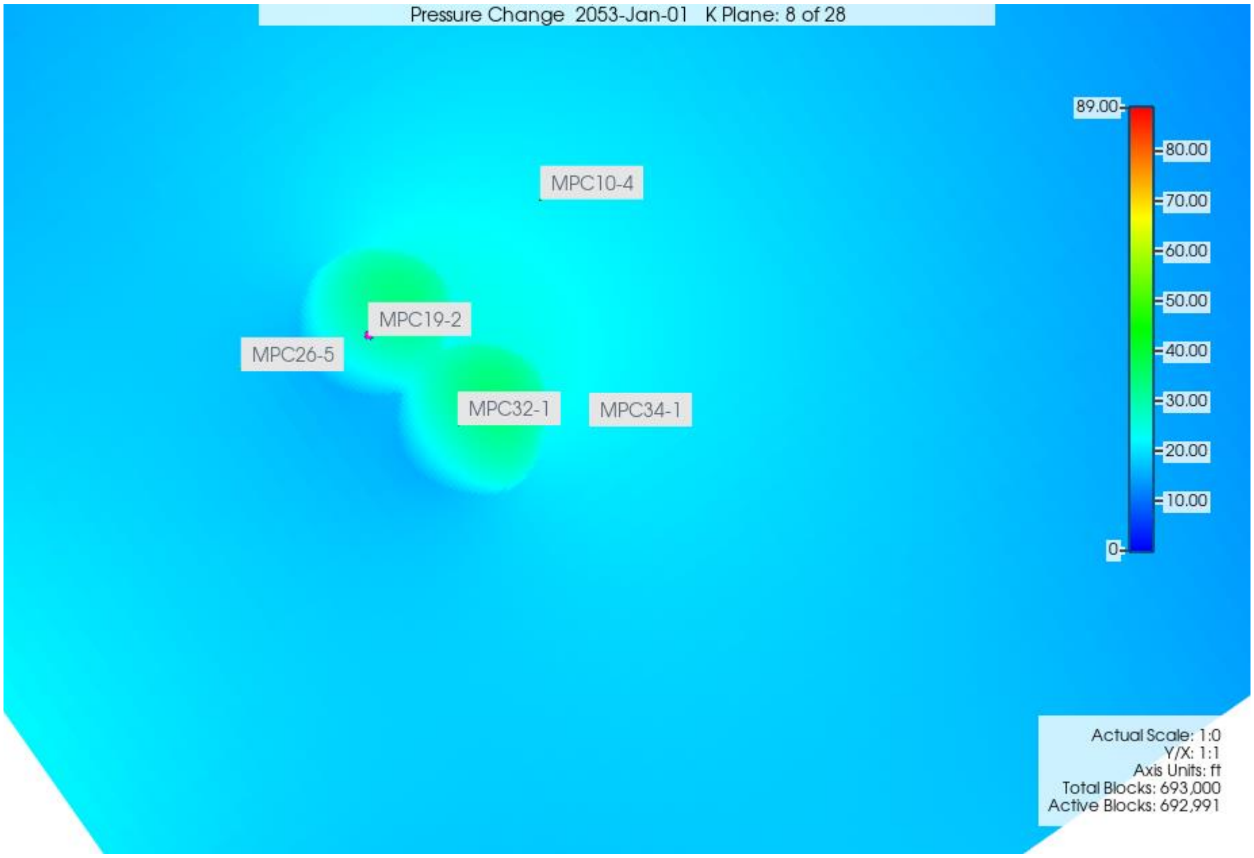

Figure 16: Pressure Buildup Two Years after the End of Injection

Modeling results show vertical migration of CO_2 to the top of each injection zone, followed by lateral migration in the direction of the structure dip. **Figure 17** shows a 3D view of the mobile CO_2 plume shape in the Paluxy Formation at the end of the 30-year injection period. The forecast CO_2 plume view in **Figure 17** shows the Paluxy Zone 3 sandstone as being the geologic horizon with the greatest plume extent in the reservoir simulation (this is expected due to more favorable permeability and porosity) and will consequently be used to determine the plume extent. It is important to note that these cross-sections include mobile CO_2 only, meaning the CO_2 trapped due to relative permeability hysteresis is not included in the plume extent. **Figure 18** also shows a top view of the largest CO_2 plume in the Paluxy formation at the end of the 30-year injection period. The plume measures approximately 3 miles along the dip (2 miles up dip and 1 mile down dip) while it extends approximately 5 miles across.

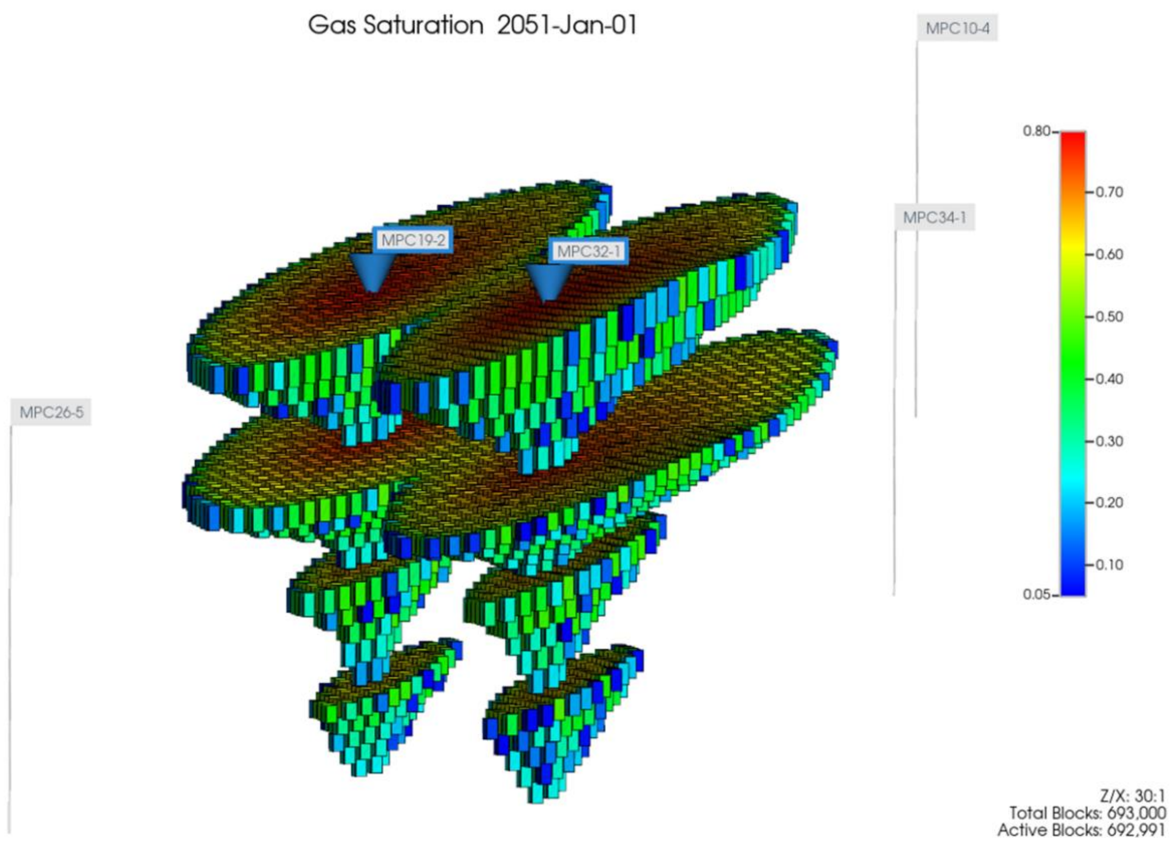

Figure 17: 3D View of Mobile Gas Saturation at End of 30-year Injection

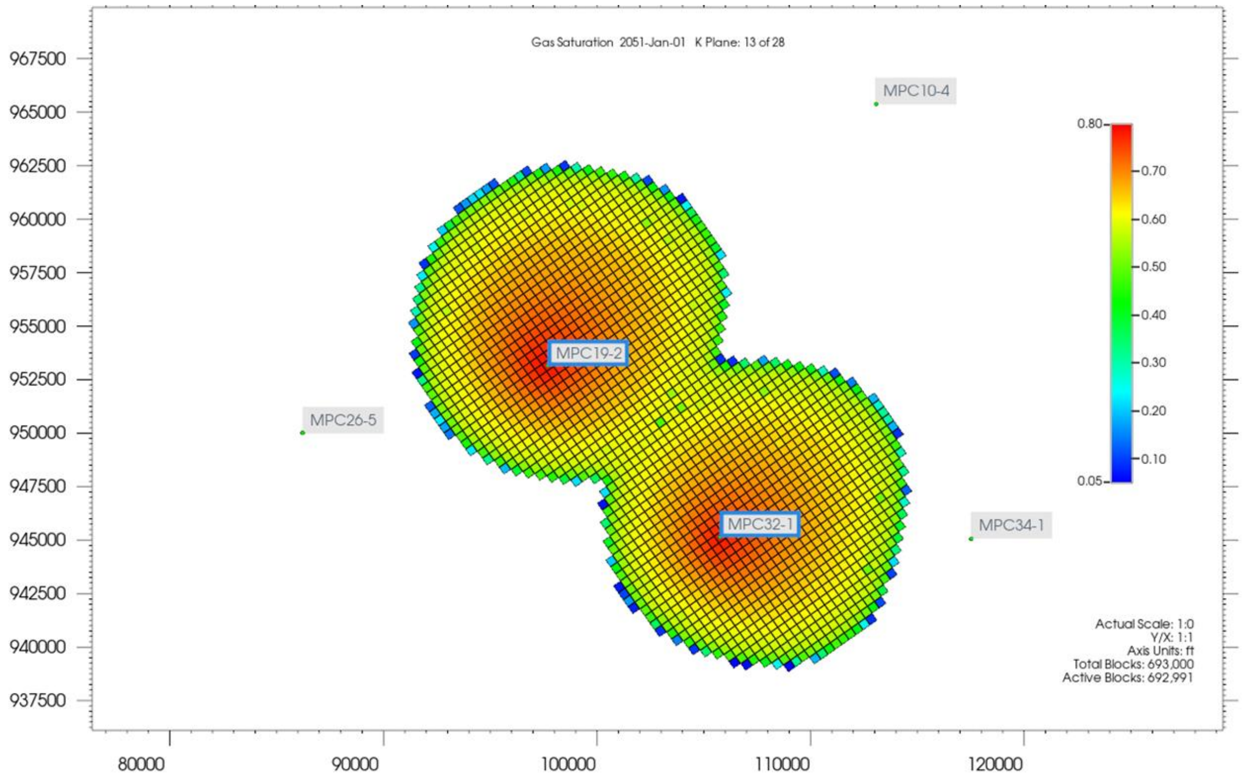

Figure 18: Largest CO2 Plume Top View at the End of 30-year Injection

Figure 19 compares the map view of the CO_2 plume in Paluxy Zone 3 at the end of injection and at 10, 20 and 30 years after the end of injection, highlighting how the plume has moved up-dip while being stabilized down dip. In addition, **Figure 20** shows the same results as **Figure 19**, but in a cross-section view. The cross-section is shown along the formation dip to better illustrate the evolution of the plume in that direction. Ten years after the end of injection, the plume extent up-dip from the injection well increased from 9,800 feet (1.9 mile) to 11,400 feet (2.2 mile) with a significant decrease in CO_2 saturation. Twenty years after the end of injection, with CO_2 saturation still decreasing, the plume extent up-dip increased to 13,400 feet, or 2.6 miles. Thirty years after the end of injection, the plume movement sensibly slows down as its extent up-dip from the injector only increased by 800 feet over 10 years to reach 14,200 feet or 2.7 miles. The plume is effectively stabilizing.

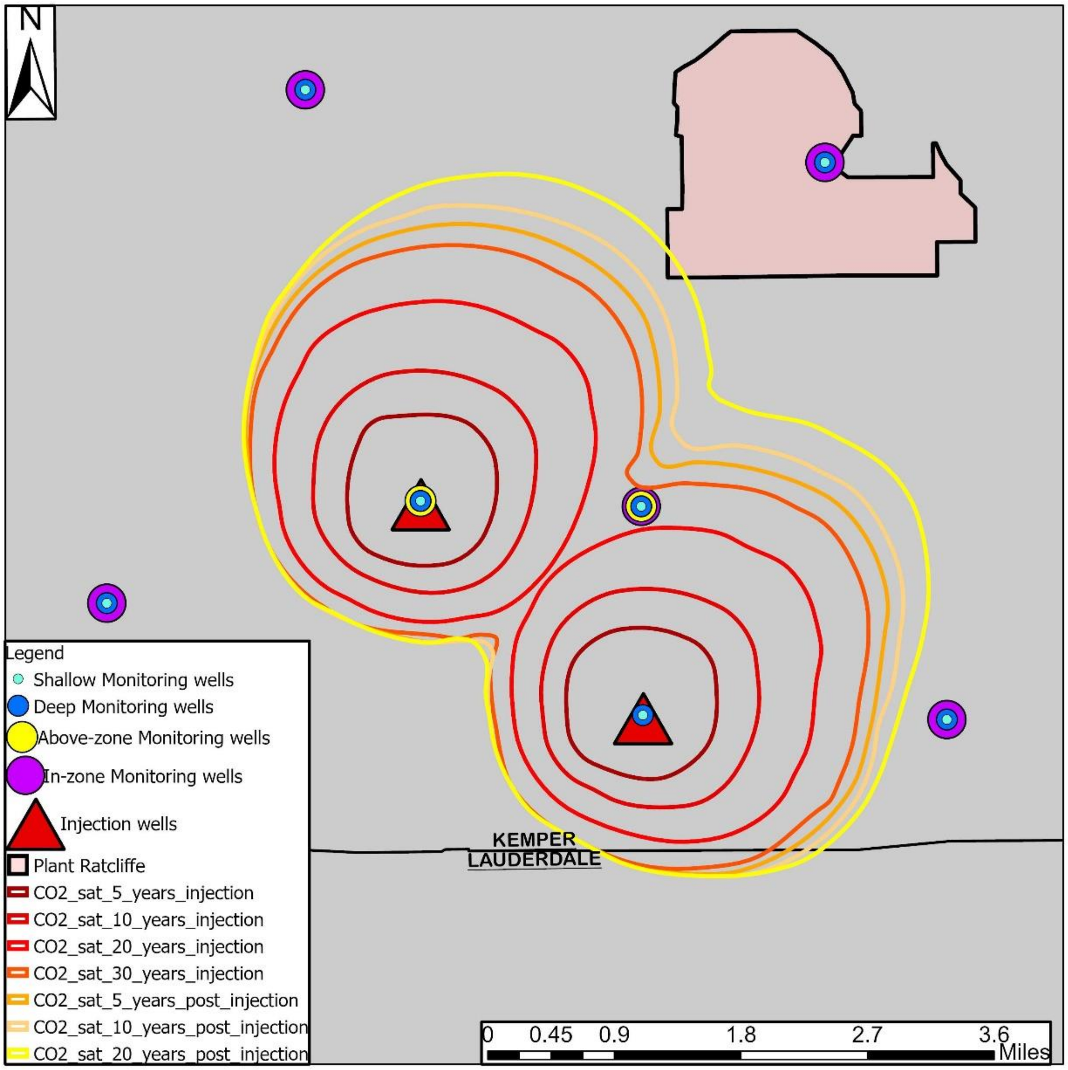

Figure 19: Evolution of CO2 Saturation Plume Extent after 20 Years of Injection, at the end of Injection, and 10, 20 and 30 Years after the End of Injection

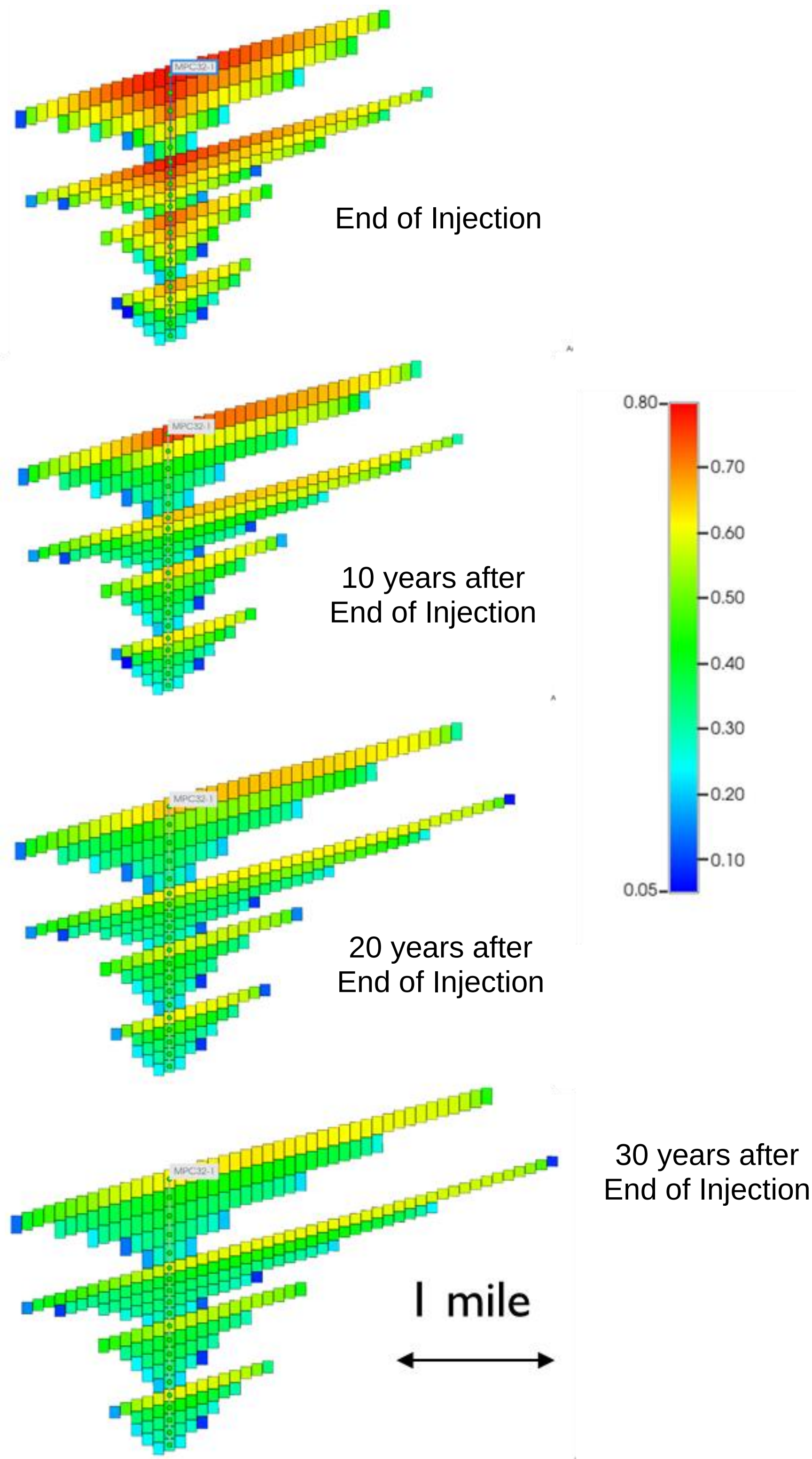

Figure 20: Cross Section Evolution of CO_2 Saturation Plume Extent at the End of Injection, and 10, 20 and 30 years after the End of Injection

Understanding the long-term fate of the injected CO_2 is paramount to ensuring a safe and secure storage project. As mineral information is not available at this phase of the project, mineral trapping is not considered.Solubility trapping and relative permeability hysteresis trapping are the only two trapping mechanisms considered.

CO_2 is soluble in water, and when injected into a pressurized saline reservoir, some of the CO_2 will dissolve in the formation water. The amount of CO_2 ultimately dissolved in water is affected by several factors including temperature and pressure within the reservoir, salinity of the reservoir water and reservoir heterogeneity and geometry.

The pressure/temperature characteristics of the reservoir are two of the primary factors in determining CO_2 dissolution. The amount of CO_2 that can dissolve in fresh water under ideal conditions will increase with additional pressure and decrease with additional temperature, **Figure 21**. Despite working against each other with depth, the effect on CO_2 solubility of pressure is stronger than that of temperature, resulting in an overall increase in CO_2 solubility with depth.

In addition to temperature and pressure, the composition of the reservoir water also plays an important role in determining how much CO_2 will dissolve. The more dissolved species, especially carbonate species, present in the water (i.e. higher salinity), the less room there is for additional CO_2 to dissolve, **Figure 22.**

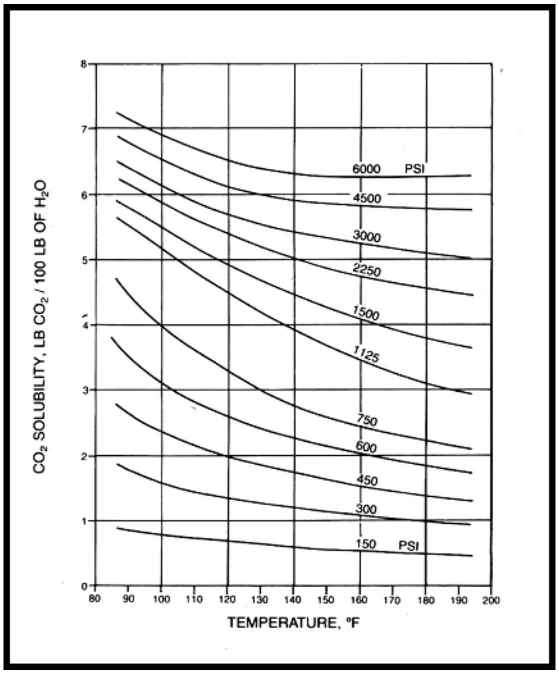

Figure 21: Effect of Temperature and Pressure on CO_2 Solubility [18]

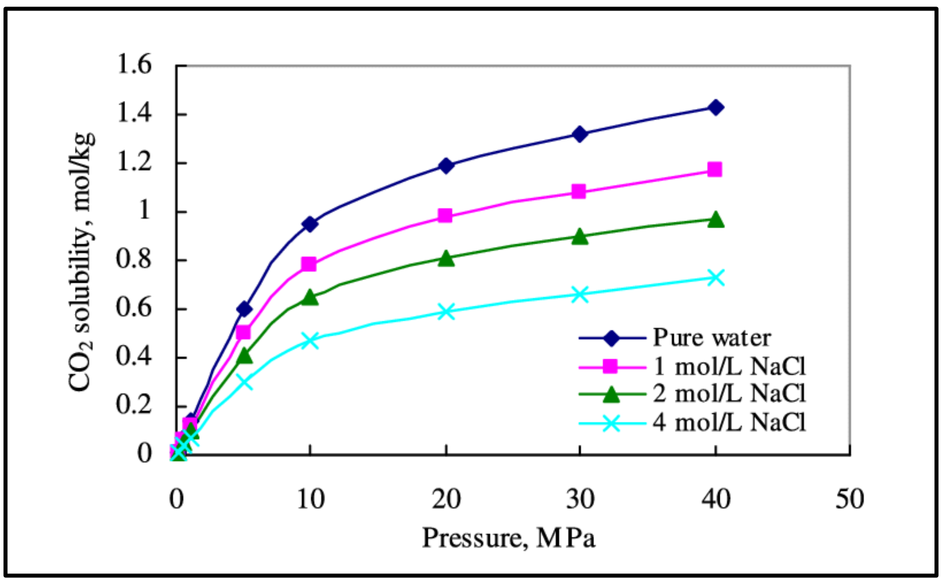

Figure 22: Effect of Salinity on CO_2 Solubility [19]

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[18] Perkins E (2003) Fundamental geochemical processes between CO_2, water and minerals. Alberta Innovates–Technology Futures

[19] Wang, Huan & Liao, X. & Zhao, Xiaoliang. (2014). The Influence of CO_2 Solubility in Reservoir Water on CO_2 Flooding and Storage of CO2 Injection into a Water Flooded Low Permeability Reservoir. Energy Sources. 36.

Under ideal conditions, all of the CO_2 is in contact with pristine reservoir water and all of the CO_2 has the potential of being dissolved with time. However, this process is substantially slowed by the geometry of the CO_2 plume. As CO_2 is injected into the reservoir, the water saturation within the plume is at irreducible conditions close to the injection site and increases outward towards the edge of the plume. Therefore, dissolution is very low closer to the injection site and increases outward. In addition, as the CO_2 along the plume edge dissolves into the reservoir water, the water in the immediate vicinity of the plume becomes saturated with CO_2 and dissolution stops until the plume contacts additional unsaturated reservoir brine. Consequently, the geometry and lithologic heterogeneity within the reservoir rock play a very important role in determining how much CO_2 will ultimately be dissolved in the reservoir water.

The presence of shale interbeds within the reservoir can serve to slow the plume's ascent (due to buoyancy), allowing more time for dissolution to occur. Shale interbeds also force the CO_2 plume to migrate laterally along the contacts of the shale beds, thereby increasing the plume's surface area and contact with the reservoir water. Both of these effects can have a strong influence on the rate of dissolution and on the ultimate amount of CO_2 stored in reservoir brine.

Once the CO_2 plume reaches the top of the Paluxy formation (the bottom of the confining unit), it essentially stops moving, whereupon it may encourage additional mixing with the native reservoir brine. Once CO_2 is dissolved in the reservoir brine, density differences within the reservoir water may cause density inversion. Density inversion is a process where the reservoir water in contact with the plume becomes saturated with CO_2, creating a slightly more dense fluid than the reservoir brine. The denser CO_2-rich water then begins to sink towards the bottom of the reservoir allowing unsaturated water to come into contact with the CO_2 plume, encouraging additional dissolution. This process is slow and may require several thousand years and large volumes of CO_2 injection.

Solubility trapping was implemented in the model and the general Henry's law was applied to compute gas solubility in the aqueous phase. The gas solubility from Henry's law is defined by **Equation 1** below.

$$\mathbf{f}_{\mathbf{CO_2,g}} = \mathbf{f}_{\mathbf{CO_2,w}} = \mathbf{y}_{\mathbf{CO_2,w}} \cdot \mathbf{H}_{\mathbf{CO_2}} \qquad (1)$$

Where:

$f_{CO2,g}$ is fugacity of CO_2 in gas phase

$f_{CO2,w}$ is fugacity of CO_2 in aqueous phase

$Y_{CO2,w}$ is mole fraction of CO_2 in water

H_{CO2} is Henry's constant

Henry's constant (H_{CO2}) is a function of pressure, temperature and water salinity, which has to be input in addition to basic water properties (density, compressibility and viscosity). Harvey (1996) published correlations to determine Henry's constants for many gaseous components including CO_2, N_2, H_2S and CH_4. These correlations have been implemented in *GEM* and the Henry's constant are calculated internally in the the simulation model.

The second CO_2 storage mechanism is relative permeability hysteresis trapping. Stated simply, hysteresis is primarily an imbalance phenomenon. While this definition may be applied to any number of observations, perhaps the simplest is the process of wetting a sponge and attempting (unsuccessfully) to wring all of the water from the sponge. Even after squeezing, the sponge will retain a percentage of water within its pore network. Theoretically, hysteresis trapping occurs because drainage (decreasing wetting phase saturation) and imbibition (increasing wetting phase saturation) gas relative permeability curves vary (for this non-wetting phase). **Figure 23** depicts an idealized pair of drainage and imbibition curves for a gas phase plotted against the gas saturation. Note that the drainage curve (1 to 2) lies above the imbibition curve (2 to 3) and that the imbibition curve has a critical saturation greater than that of the drainage curve (Sgcri > Sgcr). If the primary drainage curve is reversed at position 4 by water encroachment into a CO_2-rich plume, the depicted scanning curve (4 to 5) is the result, which effectively shifts the critical gas saturation to a higher value (Sgcrt > Sgcr).

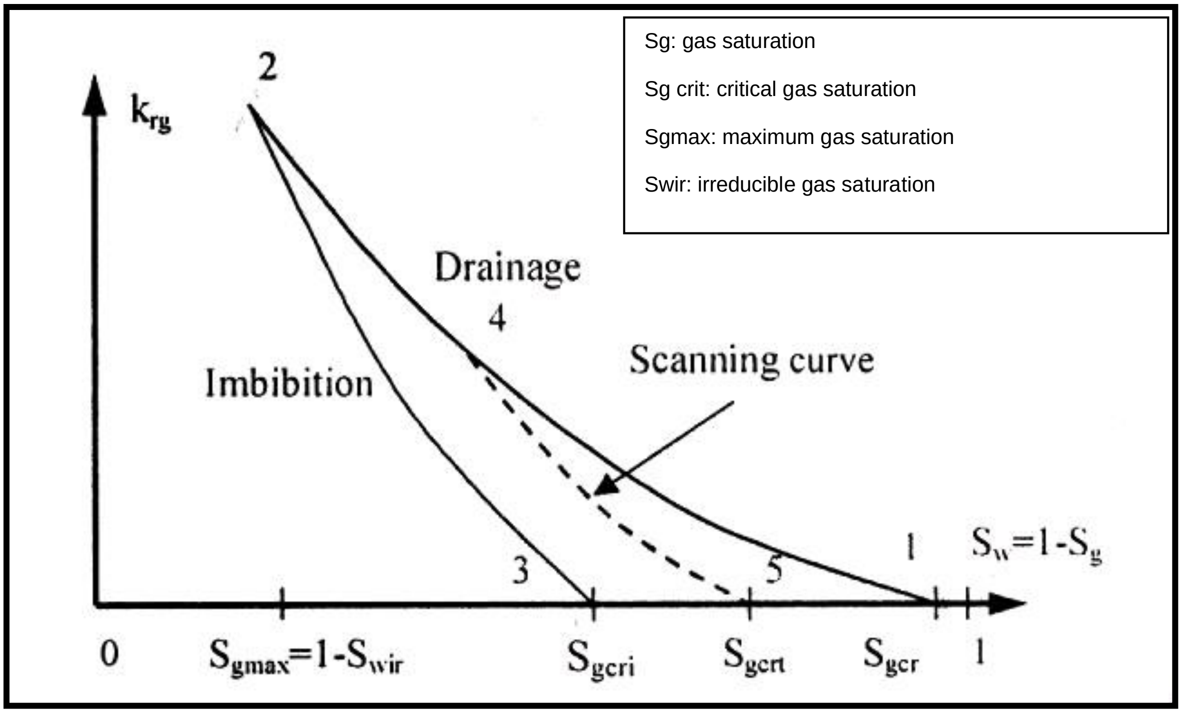


Figure 23: Relative Permeability Hysteresis (after Mo and Akervoll, 2005)[20]

Sequestration through relative permeability hysteresis is primarily a post-injection phenomenon. Witnessed and studied as a side effect of the Water-Alternating-Gas (WAG) enhanced oil recovery (EOR) methodology, this process was shown to result in trapped gas saturations on the order of 20 to 25 percent by pore volume for the South Cowden (Permian Basin, Texas) CO_2-EOR flood[21]. During sequestration of CO_2, this process occurs when water encroaches upon the CO_2 plume. Because continuous CO_2 injection typically overpowers natural water flow, the impact of hysteresis will occur after injection ceases and natural saline water flow becomes the dominant flow mechanism in the reservoir. At this point, drainage-imbibition hysteresis will occur along with a shift in the formation's characteristic relative permeability, resulting in a larger retention of supercritical CO_2 within the pore space. At the head of the plume, drainage will be predominant as water drains away from the rising (buoyant) CO_2. At the bottom of the

[20] S. Mo, I. Akervoll, 2005: Modeling Long-Term CO_2 Storage in Aquifer with a Black-Oil Reservoir Simulator, SPE 93951, SPE/EPA/DOE Exploration and Production Environmental Conference, Galveston, Texas USA, 7-9 March 2005

[21] Wegener, D.C., and K.J. Harpole. "Determination of Relative Permeability and Trapped Gas Saturation for Predictions of WAG Performance in the South Cowden CO2 Flood." Paper presented at the SPE/DOE Improved Oil Recovery Symposium, Tulsa, Oklahoma, April 1996.

plume, imbibition is prevalent as water imbibes behind the migrating plume. These processes will effectively halt CO_2 migration.

The residual CO_2 saturation due to hysteresis depends on the initial gas saturation at the start of the imbibition process. The relationship between the initial CO_2 saturation and the residual saturation is observed to experience a parabola shape that can be fit with a quadratic equation[22]. Studies of residual trapping on sandstone[23,24] show that when the initial gas saturation is 0.8, the residual CO_2 saturation can be between 0.4 and 0.5 (**Figure 24**).

[22] E.J. Spiteri, R. Juanes, M.J. Blunt, F.M. Orr Jr., *A new model of trapping and relative permeability hysteresis for all wettability characteristics*, SPE 96448, SPE Annual Technical Conference and Exhibition, Dallas, TX 2005

[23] B. Niu, A. Al-Menhali, S. Krevor, *A study of residual carbon dioxide trapping in sandstone*, Energy Procedia 63 (2014) 5522-5529

[24] S. Bachu, Drainage and imbibition CO_2/brine relative permeability curves at in situ conditions for sandstone formations in western Canada, Energy Procedia 37 (2013) 4428-4436

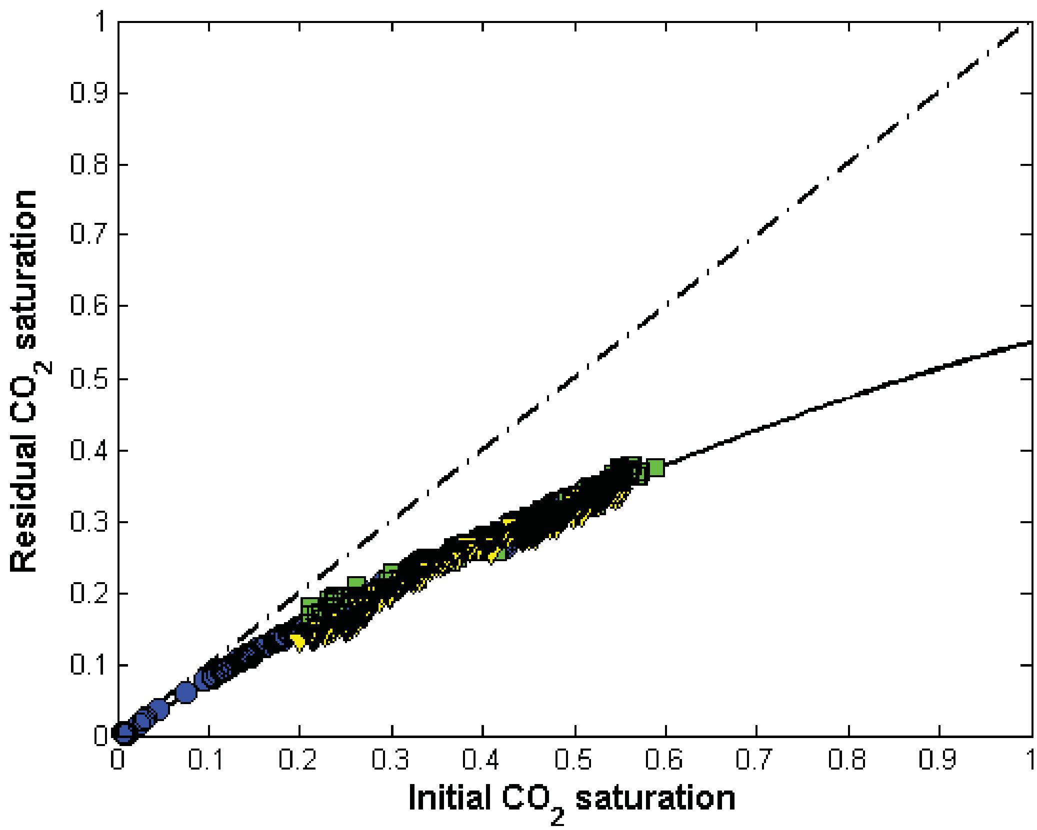


Figure 24: Residual CO2 saturation vs initial CO2 saturation (from Niu et. al.)

Since no direct reservoir data or laboratory studies were available, the maximum residual gas saturation in the model was set to 0.3 as a conservative value. Relative permeability curves and hysteresis phenomenon will be refined during the history-matching process once actual injection and pressure data become available.

For the modeling work, the injection stream is assumed to be 100% CO_2. Given the CO_2 composition and saline waters (115,000 mg/L, 2,150 psia and 130°F), we estimate through modeling that approximately 6% of the injected CO_2 volume will be dissolved at the end of the 30-year injection period (**Figure 24**). In addition, we estimate that 9% of the CO_2 will be trapped due to permeability hysteresis at the end of the 30-year injection. **Figure 24** also highlights the fact that the CO_2 stays in the supercritical state over the full course of the injection and post-injection periods. It should also be noted that supercritical phase CO_2 decreases over time, especially after injection ceases, because of continuous CO_2 dissolution in the brine.

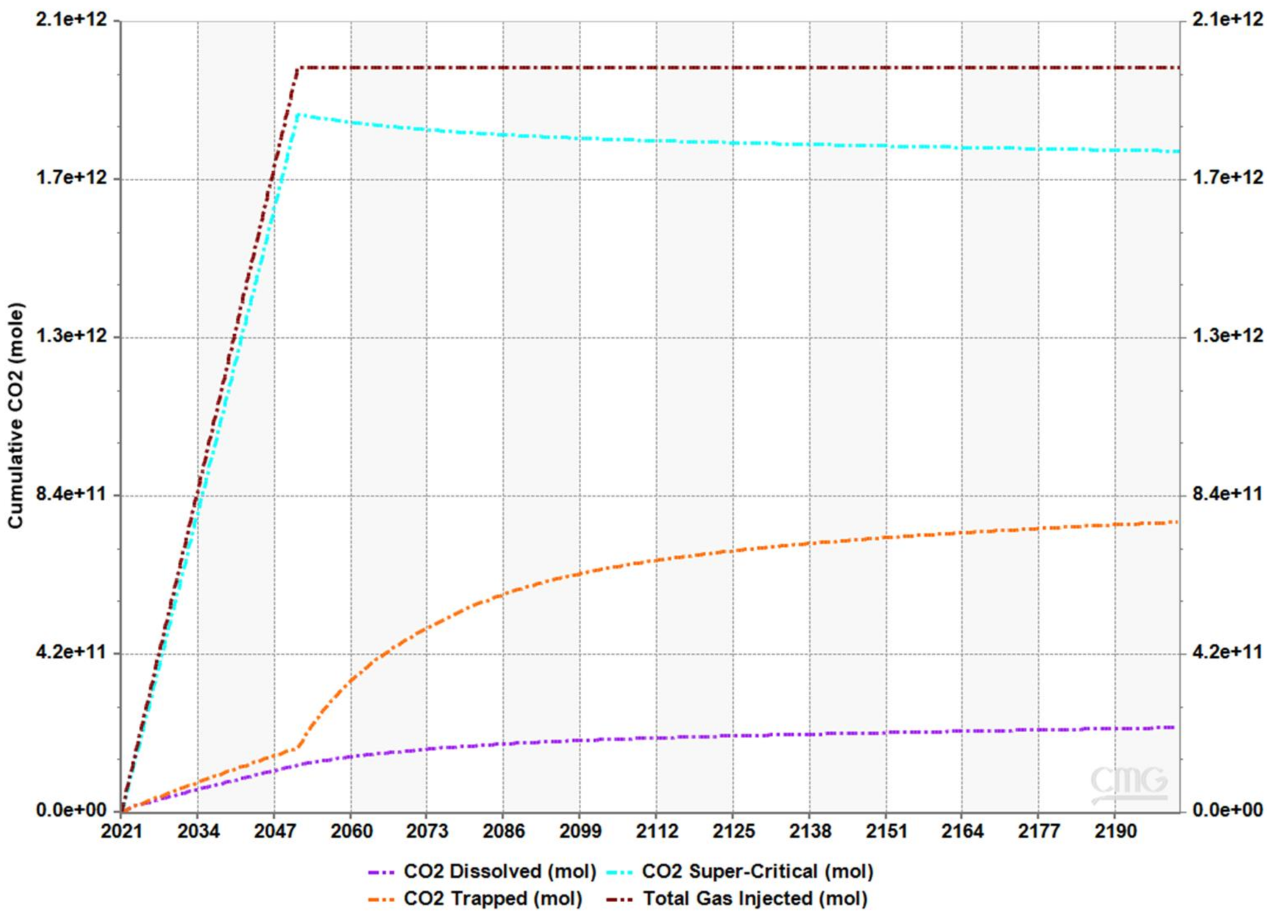


Figure 25: CO2 Dissolution and Trapping Over Injection and Monitoring Period

After an additional 150 years of monitoring, it is estimated that 11% of the injected CO_2 will be dissolved (**Figure 24**). The brines that have mixed with the CO_2 will become dense due to the transfer of some CO_2 mass from the CO_2 plume to the aqueous (water) phase during dissolution and will likely settle toward the bottom of the formation whereupon those brines without CO_2 will rise and encourage new mixing (density inversion) and dissolution. This settling process will occur over time and will be in the general direction of natural groundwater movement. In the unlikely event that direct vertical movement should occur the Mooringsport shale seal that lies at the base of the Paluxy formation will provide ample lower confinement, ensuring that the brine and CO_2 stay within the Paluxy formation. In addition, after an additional 150 years of monitoring, it is estimated that 39% of the injected CO_2 will be trapped due to permeability hysteresis.

A.4 AoR Delineation Based on Model Results

A.4.a Determination of Pressure Threshold Front

The determination of the pressure front is based on existing standard practices for other well classes in the UIC Program and involves calculation of a threshold reservoir pressure as described in the UIC Program Class VI Well Area of Review Evaluation and Corrective Action Guidance. The value of the threshold reservoir pressure that defines the pressure front may be calculated based on static pressure within the injection zone and the lowermost USDW, as well as the elevations of both zones by determining the pressure within the injection zone that is great enough to force fluids from the injection zone through a hypothetical open conduit into any overlying USDW (United States Environmental Protection Agency, 2013)[25]. At a minimum, EPA recommends that all wells be monitored for pressure changes on a monthly basis during the injection phase. Monitoring frequency may need to be increased if the results of monitoring indicate pressure increases greater than modeling predictions or indicate fluid leakage.

The pressure based AoR is defined by the pore pressure buildup $\Delta(P_{i,f})$ isoline (**Equation 2** of the following magnitude within which it can cause vertical flow from the injection zone into the USDW. This pressure front methodology is applicable to any Class VI injection well for which, prior to injection, the injection zone is not over pressured compared to the lowermost USDW (refer to Section 2.1.6 of the *Conceptual Model* regarding the slightly under-pressured gradient in the Paluxy formation.

Equation 2

$$\Delta P_{i,f} = P_u + \rho_i g(z_u - z_i) - P_i$$

Where,

$\Delta P_{i,f}$ = minimum pressure buildup within the injection zone necessary to cause vertical flow from the injection interval into the USDW, MPa

[25] EPA (U.S. Environmental Protection Agency). 2013. Geologic Sequestration of Carbon Dioxide, Draft Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance for Owners and Operators. EPA 816-R-13-005, Washington, D.C.

P_i = initial pressure in the injection zone, MPa

P_u = pressure within the lowermost USDW, MPa

ρ_i = fluid density in the injection zone, kg/m3

g = acceleration due to gravity, 9.8 m/s2

z_i = injection depth, m

z_u = depth of the lowermost USDW, m

The lowermost USDW is in the Upper Cretaceous Eutaw formation, with an average depth of 2,250 feet. The pressure increase necessary to cause vertical flow was computed to be 89 psi, using the following parameters:

Table 12: Parameters Used to Calculate Pressure Threshold

Parameter	Value
USDW depth, meter	686
Initial fluid pressure in the USDW, MPa	6.67
Top of injection zone elevation, meter	1,538
Initial fluid pressure in the injection zone, MPa	2,170
Fluid density in the injection zone, kg/m3	1,067

A.4.b AoR Delineation

The AoR is based on the *Maximum Extent of the Separate-phase Plume or Pressure-front* methodology over the lifetime of the project, as detailed in the Underground Injection Control (UIC) Program Class VI Well Area of Review Evaluation and Corrective Action Guidance (USEPA, 2013). **Figure 25** shows in green the maximum extent of the pressure front (area over the computed threshold pressure of 89 psi) and in red the extent of the CO_2 saturation plume two years into injection. After 2 years of injection, the pressure front area decreases while the CO_2 saturation plume keeps on increasing (refer to **Figure 19**). As such, based on computer modeling of the proposed injection- and post-injection period, the Area of Review is exclusively defined by the CO_2 saturation plume and not by the extent of the pressure front.

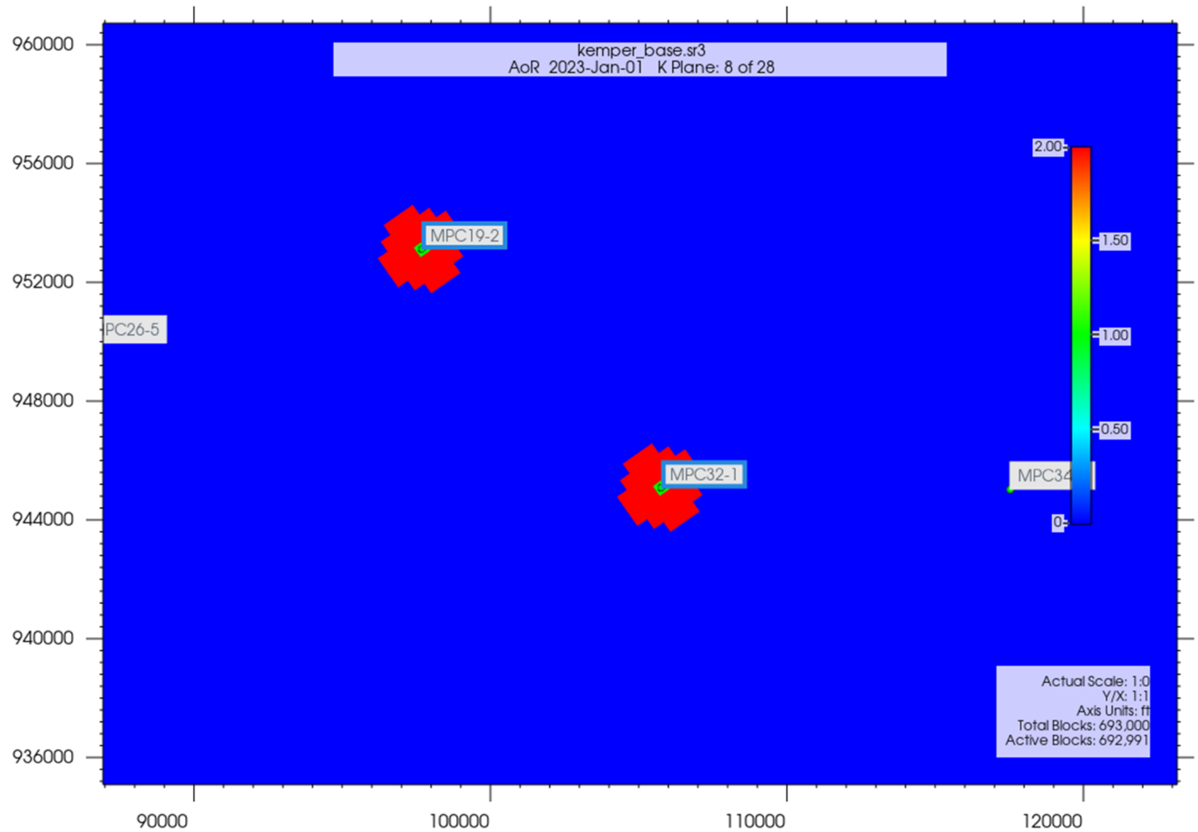


Figure 26: Pressure Front and CO_2 Plume Extent 2 Years into Injection

As illustrated on **Figure 19**, the CO_2 saturation plume has essentially stabilized 20 years after the end of injection. While it is still mobile, it is predictable. Thus, the Area of Review is computed at 20 years after the end of injection. At this stage, the CO_2 saturation plume covers an area of approximately 16 square miles, **Figure 26,** and is well contained within the monitoring wells.

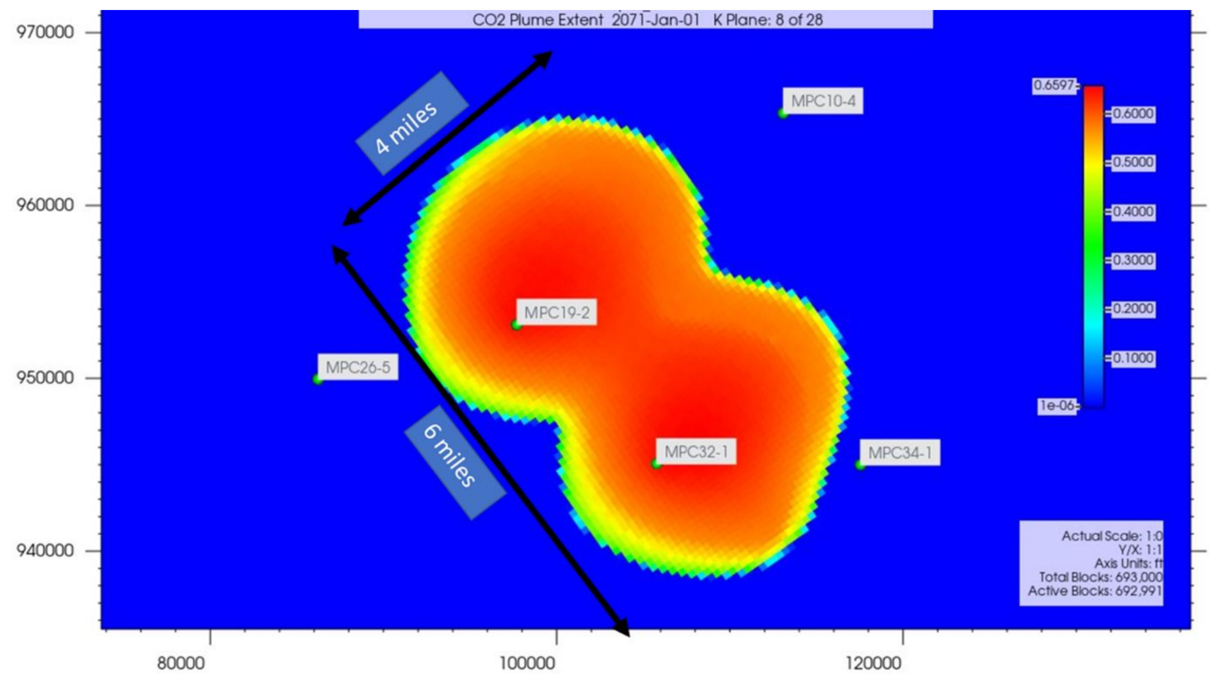


Figure 27: Area of Review at 20 Years after the End of Injection

B.0 Identifying Artificial Penetrations and Performing Corrective Action

B.1 Corrective Action Rule Requirements

According to the EPA UIC Class VI Well Area of Review Evaluation and Correction Action Guidance, the following Class VI Rule requirements apply to corrective action within the AoR:

40 CFR 146.84(c)(2): Using methods approved by the UIC Program Director, identify all penetrations, including active and abandoned wells and underground mines, in the AoR that may penetrate the confining zone(s). Provide a description of each well's type, construction, date drilled, location, depth, record of plugging and/ or completion, and any additional information the UIC Program Director may require;

• 40 CFR 146.84(c)(3): Determine which abandoned wells in the AoR have been plugged in a manner that prevents the movement of carbon dioxide or other fluids that may endanger USDWs, including use of materials compatible with the carbon dioxide stream;

• 40 CFR 146.84(d): Perform corrective action on all wells in the AoR that are determined to need corrective action, using methods designed to prevent the movement of fluid into or between USDWs, including use of materials compatible with the carbon dioxide stream, where appropriate;

• 40 CFR 146.84(e)(2): During the AoR reevaluation process, identify all wells in the reevaluated AoR that require corrective action in the same manner specified in 40 CFR 146.84(c);

• 40 CFR 146.84(e)(3): Perform corrective action on wells requiring corrective action in the reevaluated AoR in the same manner specified in 40 CFR 146.84(d);

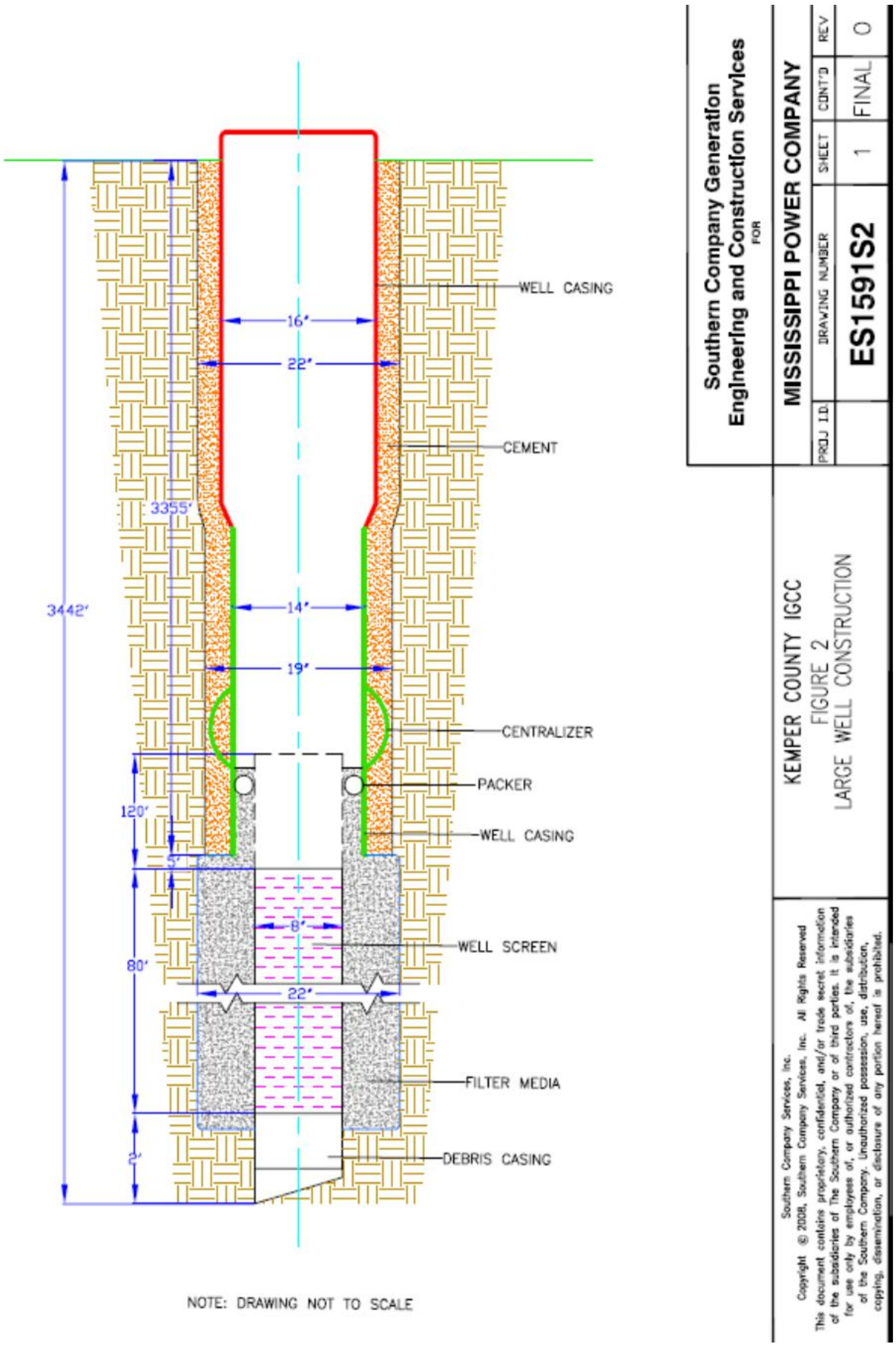
• 40 CFR 146.84(e)(4): Revise the AoR and Corrective Action Plan as necessary whenever the AoR is reevaluated.

B.2 Identifying Artificial Penetrations within the AoR

A total of seven wells have been identified within the AoR. MPC is responsible for drilling six of the seven wells during the characterization efforts at the Kemper Storage Complex. MPC drilled and completed these six characterization wells in compliance with Class VI regulations, including proper abandonment procedures for wells that will not be converted to monitoring wells. The one older well (Kemper Deep Water Well) was drilled and completed in 2008, reaching a total vertical depth of 3,442 ft. MPC's Kemper Deep

Water Well served as a water disposal well over the last decade. Given that this water disposal well does not penetrate the primary confining zone (Tuscaloosa Marine Shale), MPC concluded that this well did not pose a risk for CO_2 migration above the primary confining zone. More information on the Plant Ratcliffe Deep Water Test well is elaborated below.

The deep water production test well is located approximately 4.5 miles from the site, at the energy facility property and has a total depth of 3,442 ft. This well was drilled in 2008 to test the potential of the Lower Tuscaloosa Formation Massive sand to serve as a working fluid for the facility. The casing shoe was drilled out with a 19 inch underreamer and the borehole advanced from the bottom of casing at 3,355 feet bgs to the screen depth of 3,442 feet bgs. Eighty feet of 8-inch diameter 20-slot (0.020) stainless steel screen was used. Once the screen was placed, a 16/30 filter pack was placed around the screen. While the well showed excellent potential yield (up to 500 gallons per minute per well), total dissolved solids were 23,000 milligrams per liter, too high for plant use. In November 2018 the well was permanently plugged and abandoned using three cement plugs with bentonite drilling mud circulated between the plugs. The plugged intervals included a plug from the base of the 80 ft well screen (screened interval is 3,440 ft to 3,360 ft) into the well's 14 inch casing at 2,775 ft, a 200-foot-long plug across the lowermost fresh water zone from 716 ft to 516 ft, and then another 200-foot plug at the surface (**Figure 27**). The location of the well is shown in Figure 2.



Plug 1: 2755 to Well Screens verified by tagging.

Plug 2: 716-516

Plug 3: 200-Surface

Drilling mud placed between plugs.

Drawing not to scale

Figure 28: Water Well Plugging Diagram

B.2.a Wells Penetrating the Confining Zone

A list of the six characterization wells drilled by MPC can be found below.

- MPC 10-4- drilled in 2017 to a depth of 5,445 ft
- MPC 34-1- drilled in 2017 to a depth of 5,750 ft
- MPC 26-5- drilled in 2017 to a depth of 5,872 ft
- MPC 01-1- drilled in 2020 to a depth of 5,650 ft
- MPC 03-1- drilled in 2021 to a depth of 5,760 ft
- MPC 19-1- drilled in 2021 to a depth of 5,740 ft

The average depth to the top of the Paluxy Formation is at 4,950 ft across the characterization area. It is confirmed that all six of the recently drilled characterization wells have penetrated the primary confining zone as planned in order to collect sufficient geologic and geochemical data from the injection interval. MPC has plugged the MPC 01-1 and MPC 03-1, filling the open hole sections with cement up into the 9 5/8 inch surface casing, which is set around 1,500 ft. Additional cement plugs were set in the surface casing across the fresh water zone and near the surface. Long string 5 ½ inch casing was run on the MPC 19-1 to a depth of 3,052 ft and the open hole section was filled with cement up into the casing to a depth of 3,000 ft. This completion procedure was enacted in order to convert the MPC 19-1 into an above-ground monitoring well at a later time. The MPC 10-4, MPC 26-5, and MPC 34-1 all have 5 ½ inch casing run to the respective well total depths, and have had temporarily plugged using retrievable bridge plugs. Once the bridge plugs are removed, these three wells can be converted to in-zone monitoring wells.

No corrective action is needed at this time as all penetrating wells have been plugged or cased in a manner that prevents the movement of CO_2 or other fluids that may endanger USDWs.

B.3 Assessing Identified Abandoned Wells

There are no previously abandoned wells within the delineated Area of Review.

B.4 Performing Corrective Action on Wells Within the AoR

B.4.a Plan for Site Access

This is not applicable because no corrective action is required at this time.

B.4.b Corrective Action Schedule

This is not applicable because no corrective action is required at this time.

C.0 AoR Reevaluation

C.1 AoR Reevaluation Cycle

MPC will review the AoR annually during the injection phase and once every two years during the post-injection phases to ensure the initial model predictions are adequate for predicting the extent of the CO_2 plume and pressure front. MPC will base its reevaluation of the AoR on the consistency of the modeled extent of the plume and pressure front with actual project data.

Monitoring and operational data include data from the two injection wells, in-zone monitoring wells, above-zone monitoring wells, deep USDW monitoring wells, and shallow groundwater monitoring wells. Monitoring activities to be conducted are described in more detail in the *Testing and Monitoring Plan*. Project data from the two injection wells and all monitoring wells will be compared with the predicted CO_2 plume migration to ensure the two are consistent. The following are specific activies we will use:

- Using PNC/RST and temperature logs, flow profile surveys, and fluid sampling to locate and track the movement of the CO_2 plume in the injection formation. As detailed in the *Testing and Monitoring Plan*, PNC/RST and temperature logs, and flow profile surveys will be conducted annually during the injection period. Fluid sampling will occur annually at in-zone monitoring wells until it is observed that the CO_2 plume has reached that well.

- Verifying operating injection rates and pressures are consistent with the modeling inputs.
- Evaluating pressure data from the annulus, and above-zone monitoring wells, as detailed in the *Testing and Monitoring Plan*, to ensure no evidence of CO_2 leakage.
- Any new or updated geologic data that has been acquired since the last modeling effort will be evaluated in the model inputs/assumptions to determine if the AoR requires reevaluation.
- Reviewing ground water monitoring data to verify there is no evidence of leakage of CO_2 or formation fluids that represent an endangerment to any USDWs.

All of the monitoring and operational data will be compared with the results of the initial computational modeling used for AoR delineation to show that the model accurately represents the Kemper County Storage Complex. Statistical methods will be employed to correlate the data and confirm the model's ability to accurately represent the storage site.

MPC will prepare a report demonstrating that no reevaluation of the AoR delineation is necessary if the information reviewed is consistent with the most recent modeling assumptions and predictions about the migration extent of the plume and pressure front. If it is found that the geologic characterization or behavior of the plume or pressure front are not consistent with the most recent model's predictions, and that the actual plume or pressure front extend beyond what is modeled, MPC will re-delineate the AoR. If necessary, re-delineation will include the following steps:

- Calibrating the model with new site characterization, operational, or monitoring data (pressures and fluid saturations).
- Performing a new AoR delineation with the same methods described in the Computational Modeling portion of this permit.

- Identify any new wells that penetrate the confining zone within the new AoR and provide a description of each well's type, construction, date drilled, location, depth and records of plugging and/or completion.

- Perform corrective action on all new wells that penetrate the confining zone within the newly defined AoR to ensure that they will not act in such a way as to promote the migration of CO_2 or other fluids that endanger any USDWs.

If the reevaluation process results in the re-delineation of the AoR, MPC will prepare a report to be submitted to EPA that details the decision to update the AoR delineation, the data evaluated used to make the decision, and any necessary changes to the corrective action plan.

C.2 Triggers for AoR Reevaluations Prior to the Next Scheduled Reevaluation

As stated above, MPC plans to review the AoR every year during the injection phase and every two years during the post-injection phase. As detailed the *Testing and Monitoring Plan*, monitoring and operational data are reviewed more frequently and could suggest that the actual extent and movement of the plume or pressure font have deviated significantly from the modeled predictions. Therefore, it may be necessary to initiate a reevaluation of the AoR prior to the next scheduled reevaluation period. The following is a list of unexpected changes in the quantitative parameters that could trigger reevaluation of the AoR.

- **Pressure:** Unexpected changes in injection pressure, reservoir pressure or above-zone pressure that are of concern.

- **Temperature:** Unexpected changes in temperature that are of concern.

- **RST Saturation:** Unexpected changes in CO_2 saturation that indicate the movement of CO_2 out of the injection formation and above the confining zone. If this change is due to well integrity, no AoR reevaluation will be triggered and the well integrity issue will be addressed.

- **Deep Ground Water Sampling:** Unexpected changes in groundwater geochemical and physical parameters that may indicate movement of CO_2 and formation fluids from the injection zone and into formations above the confining zone.

Other events that may trigger an AoR reevaluation include the following:

- Seismic event greater than M3.4 within 8 miles of the injection wells, if it is likely that the actual plume or pressure front extend beyond what is modeled.
- The volume of CO_2 injected is larger than what is initially permitted.
- New site characterization data become available that significantly modifies the extent of the plume or pressure front beyond what is predicted by the initial model. This can include the identification of a previously unknown fault or fracture in the confining or injection zones.

MPC will report any such events to the UIC Program Director to determine if an AoR reevaluation is required. If an unscheduled reevaluation is triggered, MPC will perform the steps described at the beginning of this section of this Plan.